BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240012-EG

Commission review of numeric conservation goals (Florida Power & Light Company).
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DOCKET NO. 20240013-EG

Commission review of numeric conservation goals (Duke Energy Florida, LLC).
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DOCKET NO. 20240014-EG

Commission review of numeric conservation goals (Tampa Electric Company).
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DOCKET NO. 20240015-EG

Commission review of numeric conservation goals (Florida Public Utilities Company).
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DOCKET NO. 20240016-EG

Commission review of numeric conservation goals (JEA).
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DOCKET NO. 20240017-EG

Commission review of numeric conservation goals (Orlando Utilities Commission).
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PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, August 8, 2024

TIME: Commenced: 2:30 p.m.
Concluded: 2:50 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
TALLAHASSEE, FLORIDA
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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Derrick M. Craig was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240015-EG - In re: Commission review of numeric conservation goals (Florida Public Utilities Company).

DIRECT TESTIMONY OF DERRICK M. CRAIG

On behalf of Florida Public Utilities Company

I. Introduction

Q. Please state your name, occupation and business address.

A. My name is Derrick M. Craig. I am the Manager of Energy Conservation for Florida Public Utilities Company (FPUC). My business address is 208 Wildlight Avenue, Yulee, FL 32097.

Q. Describe briefly your educational background and professional experience?

A. I graduated from the Georgia Institute of Technology in 1991 with a Bachelor's degree of Electrical Engineering, and I obtained a Masters of Business Administration in 1997 from the Darden Graduate School of Business (the University of Virginia). I have worked in various engineering and financial analysis roles for several utilities, including Baltimore Gas and Electric, Oglethorpe Power Company and Southern Company. I have been employed with FPUC since 2019, where I started my career as a Regulatory Analyst before being promoted to Energy Conservation Manager in 2021.

Q. What is the purpose of your testimony in this docket?

A. The purpose of my testimony is to (1) discuss FPUC's commitment to energy conservation and demand-side management (DSM), both historically and presently; (2) describe the comprehensive methodology used in assessing

FPUC's forthcoming DSM objectives for the upcoming 10-year period; and (3) elucidate FPUC's proposed DSM goals along with its strategy for conservation programs.

Q. Are there any exhibits that you wish to sponsor in this proceeding?

A. Yes. I am sponsoring the following exhibits: Exhibit No. __[DMC-1] is a copy of my curriculum vitae; Exhibit No. _____ [DMC-1] is a listing of FPUC's current DSM and Conservation Programs; Exhibit No. ____ [DMC-3] is a summary of the historical participation rates in FPUC's current, approved DSM programs, and Exhibit No.___[DMC-4] is a table reflecting the FPUC's current goals as established in Docket No. 20190017-EG.

Q. Please describe FPUC's service territories and the customers it serves.

A. In this context, FPUC operates as an electric utility subject to the Commission's jurisdiction under Chapter 366, Florida Statutes. With an electric customer base of just over 33,000, FPUC provides electric distribution services in two distinct, non-contiguous service territories known as the Northeast Division and the Northwest Division. The Northeast Division serves approximately 18,000 customers on Amelia Island, including the City of Fernandina Beach, while the Northwest Division serves approximately 15,000 customers in the City of Marianna and adjacent areas, encompassing portions of Calhoun, Jackson, and Liberty counties in Florida's panhandle region. FPUC primarily serves residential customers across the two divisions, although it does serve some commercial and industrial customers.

II. Historical Context for FPUC's Goals and Plan

Q. What are FPUC's current Conservation Goals based upon?

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A. FPUC's current goals, consistent with Order No. PSC-2019-0509-FOF-EG, are based upon the continuation of the goals set for FPUC in Docket No. 20130205-EI using a proxy methodology.

Q. Is there an impact to FPUC's DSM programs associated with building code changes and appliance efficiency improvements?

A. Yes. As noted later in my testimony and in the testimony of Witness Herndon, there is a notable impact. As building codes apply heightened standards and appliances become more and more efficient, it becomes more difficult to design programs that effectively achieve improved efficiency levels while still demonstrating savings in the required timeframe.

Q. Please describe the evolution of FPUC's DSM Plan and its current DSM programs.

A. The Commission initially established conservation goals for FPUC in 1996, concentrating on cost-effective conservation programs evaluated under the Ratepayer Impact Measure (RIM) and Participant Tests.

In 2008, FPUC joined forces with other Florida utilities subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA), Sections 366.80 et seq., Florida Statutes, collectively referred to as FEECA utilities. They collaborated to hire a single contractor, Itron, tasked with identifying DSM measures and assessing the technical, economic, and achievable potential for DSM across each utility's service areas.

By 2015, FPUC proposed modifications to its DSM Plan based on revised conservation goals established through a proxy methodology approved by the Commission in Order PSC-2013-0645-PAA-EU. The adjusted DSM Plan gained Commission approval, as evidenced in Order No. PSC-2015-0326-PAA-EU and Consummating Order No. PSC-2015-0360-CO-EU.

In 2018, FPUC once again collaborated with other FEECA utilities to collectively engage an experienced external engineering consultant (Nexant). This consultant was assigned the task of evaluating the technical, economic, and achievable potential for DSM measures tailored to the service areas of each utility. None of the DSM measures examined were deemed cost-effective under the RIM scenario, prompting FPUC to suggest that it would be appropriate for the Commission to establish no goals for the Company, but to nonetheless allow FPUC to maintain its existing conservation programs. In that proceeding, the Commission ultimately determined that it would be appropriate for the Company to adhere to its previously established goals for the remainder of the 10-year period, as reflected in Order No. PSC-2019-0509-FOF-EG, issued November 26, 2019.

In anticipation of the ongoing FEECA DSM goals docket, FPUC collaborated with other FEECA utilities to collectively finance the retention of Resource Innovations, an engineering consulting firm. This firm was responsible for assessing the technical potential for energy efficiency in the state of Florida. FPUC's proposed goals are informed by the measures and programs evaluated as a result of this initiative.

Q. What is FPUC's approach to designing and implementing DSM programs?

A. Given that FPUC is the smallest FEECA utility and the only non-generating electric utility, the Company utilizes its constrained resources to maximum effect. With that perspective, FPUC has found that educating customers about the advantages of energy efficiency and conservation is a critical and cost-effective component of its DSM Plan. The Company places significant emphasis on advocating for zero-cost or low-cost energy efficiency and conservation measures through its customer education initiatives.

Q. Since FPUC is the only non-generating utility to which FEECA applies, please outline how the Company acquires the electricity to supply its customers?

A. Florida Public Utilities Company utilizes power purchase agreements to obtain the wholesale electricity needed for its customers. Two of these wholesale contracts, both of which are with Florida Power and Light, have been extended through December 31, 2026, and obligate the counterparty to provide FPUC with the electricity needed to meet its customers' demand. The Company also has two negotiated agreements with Qualifying Facilities (QFs), and purchases as-available power from a third under its Standard Offer (As-Available) rate schedule:

QF	**Contracted Amount**	**Expiration Date**
Eight Flags	21 MW	2036
Rayonier	Up to 3 MW	2036
WestRock	As Available	Not applicable

Q. Does FPUC have a Demand Response (DR) program?

A. No, FPUC currently does not have an established Demand Response program, even though it has implemented time-of-use rates in its Northwest Division for experimental purposes. The integration of Demand Response (DR) has not been included in FPUC's goals, and the assessment indicates that DR Programs have not proven to be cost-effective.

Q. Please provide additional detail regarding FPUC's current demand-side management programs.

A. As mentioned earlier, FPUC's Demand-Side Management Plan for 2015 received approval in August of the same year. As part of its ongoing DSM strategy, FPUC has executed the following programs: Residential Energy Survey, Residential Heating and Cooling Upgrade, Commercial Heating and Cooling Upgrade, Commercial Chiller, and Commercial Reflective Roof.

Since 2015, the Residential Energy Survey program recorded a total of 1,504 participants, and the Residential Heating and Cooling Upgrade saw the engagement of 1,474 participants over the same period. The Commercial Heating and Cooling Upgrade had a total of 9 participants since 2015. As for the Commercial Chiller program it had one participant, while the Commercial Reflective Roof program garnered 87 participants.

In 2023, FPUC notably surpassed the residential winter peak demand and energy reduction goals but, for the first time, did not meet its summer demand goal. The primary factor behind the goal exceedance was the remarkably high participation rate in the Residential Heating and Cooling Upgrade Program. However, with no commercial participants in 2023, FPUC fell short of the commercial/industrial winter peak and energy reduction goals, resulting in an overall shortfall in meeting the Total Energy Savings Goals for all programs and classes. Only 65% of the GWh Energy goals were achieved, along with

93% of the Winter Demand goals and 54% of the Summer Demand Goals.

III. Evaluation of New Goals

Q. What cost-effectiveness test or tests should the Commission use to set new DSM goals for FPUC, pursuant to Section 366.82, F.S.?

A. FPUC recommends that the commission use the approach that was previously approved in the rule development proceeding prior to the current DSM goals docket. This approach involves providing multiple scenarios, including a portfolio of RIM and Participants Test-based programs, as well as a portfolio of TRC and Participants Test-based programs, to the commission for goal setting. Given that no measures passed the RIM portfolio, FPUC is now proposing goals derived from a portfolio based on TRC results.

Q. How were potential new DSM measures identified and evaluated for FPUC for purposes of this proceeding?

A. The DSM measures assessed for FPUC resulted from collaboration with other FEECA utilities to evaluate the technical potential for energy efficiency, demand response, and demand-side renewable energy. This assessment was carried out through a contract with the firm Resource Innovations. The specific process of identifying and evaluating these DSM measures is described in the testimony of Jim Herndon.

Q. How was FPUC's achievable potential for the 2025 through 2034 period determined?

A. The achievable potential for FPUC was developed by Resource Innovations and is detailed in the testimony of Jim Herndon and exhibit JH-5.

Q. What are FPUC's estimated residential and commercial/industrial energy

efficiency achievable potentials based on the RIM or TRC test?

A. No measures passed the RIM screening; therefore, the proposed DSM goals are based on the TRC scenario with a 2-year minimum payback screen applied. These figures represent a 10-year goal time frame. The total achievable residential potential is 5.1 GWh, commercial potential is4.3GWh, and industrial potential is 2.5 GWh, resulting in a total 10-year goal of 11.8 GWh. The achievable summer peak MW savings are 1.0 MW for residential, 0.7 MW for commercial, and 0.3 MW for industrial, totaling 2.0 MW for the system. FPUC's achievable winter potential for residential savings is 1.2 MW, 0.7 MW for commercial, 0.3 MW for industrial, and a total of 2.2 MW for the system.

Q. Is the demand response achievable potential included in FPUC's proposed DSM goals?

A. As a result of the lack of cost-effective demand response measures, none have been incorporated into the proposed DSM programs, even after excluding the startup costs associated with demand response capability from the cost-benefit analysis.

Q. Have any residential and commercial/industrial demand-side renewable energy technologies been identified as meeting the achievable potential standard under the RIM test?

A. The study conducted by Resource Innovations concluded that there was no achievable potential for residential and commercial demand-side renewable technologies based on either TRC or RIM scenarios.

Q. Do applicable building codes and requirements for appliance efficiencies

impact the assessment of DSM technologies for FPUC under the RIM test and TRC test Scenarios?

A. Indeed, the analysis considers the impacts of energy codes and standards, specifically the Florida Building Code, Energy Conservation (8th edition), as highlighted in Jim Herndon's testimony.

Q. Does the analysis conducted by Resource Innovations provide an adequate assessment of the full technical potential of demand-side and supply-side conservation and efficiency measures available to FPUC, including demand-side renewable energy systems?

A. Yes. Resource Innovations leveraged its extensive experience of conducting over 50 similar technical potential studies to comprehensively evaluate the full potential for DSM across the state of Florida. Utilizing a combination of its diverse internal expertise, advanced software, and analytical tools, Resource Innovations thoroughly assessed the complete technical potential for achievable DSM.

Q. Does the analysis conducted by Resource Innovations provide an adequate assessment of the achievable potential of demand-side and supply-side conservation and efficiency measures available to FPUC, including demand-side renewable energy systems?

A. As a non-generating utility, supply-side conservation and efficiency measures are not applicable to FPUC, nor does it benefit from avoided units. FPUC experiences the entirety of its DSM benefits through the avoided cost of purchased electricity, and in accordance with the forecast supported by Mike Clark's testimony However, the achievable potential assessment conducted by

Resource Innovations does offer a reasonable evaluation of the potential for available demand-side conservation and efficiency measures, including demand-side renewable systems.

Q. Please provide an estimate of how the proposed goals might the conversation cost recovery factor charges paid by a residential customer using 1,000 kWh of electricity per month.

A. The proposed goals by FPUC are expected to result in an estimated cost of $1.44 per month for a residential customer using 1,000 kWh of electricity.

Q. Please provide a description of the efforts made to address customers who rent.

A. FPUC focused on prioritizing renters in conservation programs by improving and expanding energy-saving kit offerings. These kits include non-permanent, portable energy-saving devices such as LED lights, weather stripping, and pipe insulation, allowing renters to implement energy-saving measures without the need for major appliance purchases typically required by homeowners. Renters also gain access to online resources and energy survey tools for better energy management. FPUC will implement a program similar to its renter program for low-income customers.

Q. Under its proposed goals, will FPUC be able to develop programs that would be specifically beneficial to low-income customers?

A. FPUC is focused on finding ways to facilitate conservation for our lower income customers. As stated earlier in this testimony, FPUC has found that educating customers about the advantages of energy efficiency and conservation is a critical and cost-effective component of its DSM Plan, which is particularly beneficial for both lower income customers and our customers that reside in rental properties. Through proactive information programs and our energy-saving kits, we are able to provide some meaningful conservation opportunities to our lower income customers, as well as those who rent.

Q. Provide a comparison of the programs used to determine FPUC's goals to its current demand-side management program offerings.

A. FPUC's main focus was to enhance its existing programs and to develop new programs where needed. The expanded residential programs include the residential energy survey and heating and cooling upgrade initiatives. The residential energy survey program energy survey kit was enhanced to include additional items beyond LEDs, such as weather stripping, a low-flow showerhead, hot water pipe insulation, and a tube of caulking. The heating and cooling program now covers multiple tiers of air source heat pumps with increased incentives was expanded to include Energy Star-rated ground source heat pumps, Energy Star room air conditioners, smart thermostats, and Variable Refrigerant Flow (VRF) HVAC Systems. Additionally, new residential equipment rebates have been introduced in FPUC's DSM proposed goals, offering incentives for advanced-tier clothes washers and Energy Star clothes washers.

The commercial heating and cooling upgrade initiative now includes high-efficiency direct expansion units, high-efficiency package terminal heat pumps, smart thermostats, and packaged terminal air conditioners.

Additionally, FPUC will maintain its chiller upgrade program and terminate its Reflective Roof Program. Lastly, FPUC is set to introduce a new commercial lighting program, including incentives for interior lighting equipment, lighting controls, and exterior lighting.

IV. Conclusions

Q. Should the Commission establish separate goals for demand-side renewable energy systems for the period 2025 through 2034?

A. No, the Commission ought not to set distinct targets for FPUC regarding demand-side renewable energy systems. All conservation objectives for FPUC should aim to encourage cost-efficient DSM without favoring any specific technology or initiative. Additionally, if demand-side renewable energy systems prove to be cost-effective, FPUC should have the freedom to integrate such systems into their renewable portfolio or DSM objectives

Q. Should the Commission establish separate goals for FPUC for residential and Commercial/industrial customer participation in utility energy audit programs for the period 2025 through 2034?

A. No, the Commission should refrain from setting distinct objectives for residential and commercial/industrial customer engagement in utility energy audit initiatives. These audits, conducted by FPUC, are initiated upon customer request without any mandatory participation requirement. FPUC should retain the flexibility to incorporate energy audits into its conservation programs as deemed suitable.

Q. Please identify the 2025 through 2034 projected technical potential for

FPUC.

A. The projected technical potential for FPUC is presented in section 5.2 EE Technical Potential, page 32, and 5.3 DR Technical Potential, page 38, of the Resource Innovations report titled Technical Potential Study of Demand-Side Management - Florida Public Utilities Company, which is Exhibit JH-5 to Witness Herndon's testimony.

Q. What overall DSM goals (peak demand and energy reductions) are appropriate and reasonably achievable for FPUC for the 2025 through 2034 period?

A. FPUC's reasonably achievable goals for the period covering 2025 to 2034 are outlined as follows:

The 10-year total goal for residential energy efficiency is targeted at 3.8 GWh, with non-residential aiming at 2.3 GWh and an overarching energy efficiency goal of 6.1 GWh.

For summer MW goals, residential targets are set at 2.58 MW, and non-residential targets at 0.35 MW, with a cumulative total goal of 0.93 MW. Achievable winter MW goals would be 1.15 MW for residential and 0.33 MW for non-residential, culminating in a combined total winter megawatt goal of 1.83 MW.

Q. Should DSM goals nonetheless be set for FPUC to reflect the costs imposed by state and federal regulations on the emission of greenhouse

gases, pursuant to Section 366.82(3)(d), F.S.?

A. No, currently, neither the State nor Federal level regulates greenhouse gases, and there are no existing costs associated with their emissions. Therefore, it is not suitable to establish DSM goals based on speculation about future regulations on greenhouse gas emissions.

Q. Does this conclude your testimony?

A. Yes.

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(Whereupon, prefiled direct testimony of Michael T. Clark was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMISSION

DOCKET NO. 20240015-EG

IN THE MATTER OF: COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (Florida Public Utilities Company)

DIRECT TESTIMONY

OF

MICHAEL TY CLARK

ON BEHALF OF

FLORIDA PUBLIC UTILITIES COMPANY

April 2, 2024

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I. <u>Introduction</u>

Q. Please state your full name.

A. My name is Michael Ty Clark.

Q. By whom are you employed and what is your business address?

A. I am a Vice President with Christensen Associates Energy Consulting LLC ("CA Energy Consulting"). My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q. On whose behalf are you submitting testimony?

A. I am submitting this direct testimony on behalf of Florida Public Utilities Company ("FPUC") before the Florida Public Service Commission ("FPSC").

Q. Please summarize your education and professional work experience.

A. I received a Bachelor of Arts degree in Economics from Utah State University in 2011, a Master of Science degree in Economics from Florida State University in 2013, and a Doctor of Philosophy degree in Economics from Florida State University in 2015. I have been employed by CA Energy Consulting since 2015 in positions of increasing responsibility. I have testified on topics relating to marginal costs, load forecasting, and rate design. A copy of my curriculum vitae is attached as Exhibit MTC-1.

Q. Have you previously provided testimony before the Florida Public Service Commission or other state regulatory commissions?

A. While I have not testified before the FPSC, I have testified before other state regulatory commissions and I have contributed to numerous reports, studies and analyses filed with regulatory authorities, with a concentration on customer response to time-of-use tariff options, electric vehicle tariffs, and demand response programs. I have testified on behalf of

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Alpena Power Company before the Michigan Public Service Commission regarding load and energy forecasting as well as marginal cost-based rate design. I have also testified on behalf of the New Hampshire Department of Energy before the New Hampshire Public Utilities Commission with respect to a distribution utility's marginal cost of service study. The testimony addressed rate design topics focused on time-of-use, electric vehicles, and revenue decoupling.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss FPUC's avoided costs used by Resource Innovations, Inc. to conduct the Technical Potential Study for FPUC, as required by the Florida Energy Efficiency and Conservation Act ("FEECA"). My testimony summarizes FPUC's projections of avoided costs.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, Exhibit MTC-2 consists of a full report regarding FPUC's avoided costs. The report contains a detailed description of the methodology used to develop FPUC's avoided costs, as well as results, through the intermediate steps to the final application of avoided costs to FPUC's LED lighting program.

Q. How is your testimony organized?

A. Section II provides a description of avoided costs and their application in this proceeding. Section III provides a summary of FPUC's avoided cost estimates.

II. <u>Avoided Costs</u>

Q. Please describe avoided costs.

A. "Avoided cost" refers to the resource cost savings of a service provider associated with a reduction change in the services provided. Sometimes referred to as marginal costs, avoided costs are particularly important to infrastructure industries such as electricity and gas utility services. Avoided costs reflect out-of-pocket cost savings, at the margin: the reduction in the total cost incurred by a service provider with respect to a change (decrease) in the level of services provided. Avoided costs are typically measured as $/MWh for electricity services and are highly specific to the timeframe in which services are provided to consumers as they reflect the underlying resource technologies used in the production and transport of electricity from locations where it is produced to locations where it is consumed. Avoided costs can vary dramatically over the course of hours or from one day to another.

Q. Please describe how avoided cost estimates are used.

A. Calculations of avoided costs are used in the energy industry for a variety of purposes, including rate design, revenue requirement allocation, resource planning, etc. For this immediate proceeding before the FPSC, the relevant application of avoided costs is to evaluate proposed demand side management ("DSM") goals with respect to their economic cost-effectiveness. In brief, avoided costs serve as the cost benchmark by which supply- and demand-side resource options are gauged. The selection of demand-side options often involves long-term commitments, much like supply options. Accordingly, the process of resource assessment employs estimates of avoided costs over extended future years. FPUC's hourly avoided costs were estimated for years 2023-2050 and provided to Resource Innovations, Inc. for use within the process of evaluating impacts of DSM technologies.

Q. What is the structure of avoided costs and how are they estimated?

A. Avoided costs are specific to functional activity including generation, transmission, distribution and, possibly, customer and interconnection services. The estimates of avoided costs provided here are organized in a similar fashion. The generation component includes avoided cost estimates for energy, operating reserves, and capacity (estimated via scarcity pricing after 2026). Avoided costs of power delivery include transmission-related capacity costs as well as transmission- and distribution-related energy costs (as reflected by line and transformer losses). Hourly avoided costs were estimated for each of these components for the years 2023-2050. The avoided costs for years 2023-2026 were based on commercial terms of FPUC's contract with Florida Power and Light ("FPL") for generation and transmission services while the projected avoided costs for years 2027-2050 were based on electricity market simulations. Details of the methodology used to estimate avoided costs for each cost category are provided in Exhibit MTC-2.

III. Summary of Results

Q. Please discuss Florida Public Utility Company's projections of avoided costs for use in the FEECA evaluation studies.

A. Table 1 presents FPUC's estimates of avoided costs, in nominal terms, for selected years between 2024 and 2050. The average hourly avoided costs are provided for each cost component, season, and off-peak/peak timeframes. The seasonal definitions consist of May through September for summer, April and October for "shoulder" months, and November through March for winter. The "peak" period is defined as 4-9 p.m. for all months. As discussed above, the avoided cost components align with the function of providing electricity services: energy (including transmission and distribution line losses), generation capacity, and transmission capacity. All-in generation and transmission ("G&T") costs are the total of the avoided cost components. The annual average of the all-in G&T avoided costs for FPUC increase over time from $62.31 in 2024 to $142.14 in 2050, representing an annual increase of 3.2%.

Table 1: Florida Public Utility Company's Estimates of Avoided Costs, 2024-2050

Year	Cost Element	Annual	Summer		Shoulder		Winter	
			Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak
2024	Energy	50.53	47.90	47.90	48.28	48.28	54.10	54.10
	Generation Capacity	7.68	5.09	17.30	4.54	19.50	6.75	11.46
	Transmission Capacity	4.11	2.72	9.26	2.43	10.43	3.61	6.14
	All-in G&T Avoided Cost	**62.31**	**55.71**	**74.46**	**55.24**	**78.21**	**64.46**	**71.70**
2026	Energy	54.85	51.62	51.62	51.93	51.93	59.31	59.31
	Generation Capacity	7.68	4.45	19.71	3.79	22.35	5.96	14.48
	Transmission Capacity	4.35	2.52	11.16	2.15	12.65	3.37	8.20
	All-in G&T Avoided Cost	**66.88**	**58.60**	**82.49**	**57.87**	**86.93**	**68.64**	**81.99**
2027	Energy	47.11	40.08	43.28	37.53	41.97	56.21	60.27
	Generation Capacity	0.50	0.00	5.72	0.00	0.00	0.00	0.00
	Transmission Capacity	5.15	5.85	36.24	0.02	0.74	0.03	0.02
	All-in G&T Avoided Cost	**52.76**	**45.93**	**85.24**	**37.56**	**42.71**	**56.24**	**60.29**
2032	Energy	60.78	56.42	62.61	50.78	59.49	65.90	72.13
	Generation Capacity	23.84	3.36	252.65	0.00	0.00	0.73	4.97
	Transmission Capacity	5.66	6.43	39.87	0.03	0.82	0.03	0.02
	All-in G&T Avoided Cost	**90.29**	**66.21**	**355.13**	**50.80**	**60.30**	**66.66**	**77.12**
2038	Energy	75.25	69.50	78.84	62.93	74.83	81.03	90.92
	Generation Capacity	22.19	0.23	198.06	0.00	0.00	2.95	44.66
	Transmission Capacity	6.35	7.22	44.72	0.03	0.92	0.04	0.02
	All-in G&T Avoided Cost	**103.79**	**76.94**	**321.61**	**62.96**	**75.75**	**84.02**	**135.60**
2044	Energy	91.29	84.27	95.73	76.34	90.72	98.36	110.10
	Generation Capacity	14.43	2.33	99.22	0.00	0.00	2.94	46.75
	Transmission Capacity	7.12	8.09	50.15	0.03	1.03	0.04	0.02
	All-in G&T Avoided Cost	**112.84**	**94.69**	**245.10**	**76.37**	**91.74**	**101.35**	**156.87**
2050	Energy	113.25	104.91	117.63	94.77	111.24	122.47	135.04
	Generation Capacity	20.91	22.76	68.07	0.00	2.88	2.93	73.68
	Transmission Capacity	7.99	9.08	56.24	0.04	1.15	0.05	0.03
	All-in G&T Avoided Cost	**142.14**	**136.74**	**241.94**	**94.81**	**115.27**	**125.46**	**208.75**

Note: Summer is May through September, Shoulder is April and October, and Winter is November through March. Peak hours are hours-ending 17-21.

Q. Please summarize your estimates for the avoided costs of energy.

A. The average annual avoided cost of energy is expected to rise from \$50.53/MWh in 2024 to \$113.25/MWh in 2050, exhibiting an annual increase of 3.2%. The avoided cost of energy is highest during the winter period and lowest during the summer off-peak period. The higher

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avoided costs in winter are driven by the monthly pattern of projected natural gas prices as well as comparatively low-cost generators coming offline during this period for scheduled maintenance, resulting in less efficient generator units being dispatched to meet demand. Increased energy costs are also driven by rising demand in the near term. Specifically, as load levels get progressively higher, this results in more hours during which, on average, less efficient generators with associated higher fuel costs will need to be dispatched.

Q. Please summarize estimates for the avoided costs of generation and transmission capacity.

A. The annual average of avoided generation capacity costs remains unchanged for years 2024 through 2026, per the FPU-FPL power supply agreement. The annual average of avoided generation capacity costs, however, in 2027 is $0.50/MWh, which increases to $20.91/MWh in 2050.

The avoided costs for 2027 through 2050 are based on electricity market simulations. Generation capacity cost estimates reveal substantial year-over-year variation, reflecting the true nature of wholesale electricity markets: tight supply-demand balance conditions during some years and capacity-long conditions in others. A tight supply-demand balance results in higher generation capacity prices while capacity-long conditions result in lower, even zero, generation capacity prices because of scarcity pricing, which reflects the value of reliability when available generation supply is low relative to demand (i.e., prices increase as reserve margins decrease). For instance, at the time the analysis was carried out, the FRCC region was projected to be comparatively long in generation capacity in 2027, resulting in a relatively low avoided generation capacity cost average of $0.50/MWh. Similarly, between years 2027 and 2050, seasons and off-peak/peak periods with zero avoided generation capacity costs reflects durations when generation capacity is sufficient to meet demand and a reserve margin in all hours. Avoided generation capacity costs are highest during the summer peak period because these reflect hours when generation supply is low relative to demand. In short, annual, seasonal, and off-peak/peak period differentiation in avoided capacity costs are driven by evolving patterns of supply and demand conditions.

Avoided costs for transmission capacity are estimated on the basis of recent historical experience of FPL with respect to investment and operations and maintenance expenditures in transmission facilities, as reflected in their publicly available FERC Form 1. This historical view suggests that transmission costs will rise by 2.6% annually. Seasonal and off-peak/peak period differentiation in avoided transmission capacity costs is driven by evolving load patterns, as these costs are allocated amongst hours with the highest loads.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Brian Pippin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRIAN PIPPIN

ON BEHALF OF

JEA

DOCKET NO. 20240016-EG

APRIL 2, 2024

Q. Please state your name and business address.

A. My name is Brian Pippin. My business address is 225 N. Pearl St., Jacksonville, Florida, 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as a Specialist in the Grid Solutions Team.

Q. What are your responsibilities in that position?

A. My current responsibility is DSM Portfolio Management. In this capacity, I ensure that all electric demand-side management (DSM) programs are meeting the numerical goals set by the Florida Public Service Commission (Commission) during the last Florida Energy Efficiency and Conservation Act (FEECA) goal-setting cycle. I assist in the evaluation of new electric DSM measures for inclusion in JEA's DSM portfolio based upon the value the measures bring to our customers and JEA. I also consult and report on the DSM portfolio's ability to meet JEA's internal DSM goals.

Q. Please summarize your educational background and professional experience.

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A. I hold a Bachelor of Science in Industrial Engineering from the Georgia Institute of Technology and a Masters in Business Administration from the University of Memphis. I've worked at JEA for 19 years, initially providing energy and water conservation education to customers and later developing and implementing energy and water efficiency programs, to now managing the overall electric DSM portfolio to achieve our external FEECA and internal DSM goals.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss (1) how JEA is governed; (2) recent trends in JEA's system load growth; and (3) JEA's proposed DSM goals and the process used to develop them. My testimony includes discussion related to JEA's existing conservation and DSM programs, how supply-side efficiencies are incorporated into JEA's planning process, and how JEA's proposed goals encourage demand-side renewable energy systems.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. [BP-1] is a copy of my resume. Exhibit No. [BP-2] presents JEA's existing Florida Energy Efficiency and Conservation Act (FEECA) goals. Exhibit No. [BP-3] presents a list of the DSM and conservation programs included in JEA's existing DSM Plan. Exhibit No. [BP-4] summarizes the historical participation in JEA's existing FEECA DSM programs. Exhibit No. [BP-5] presents a summary of JEA's marketing and educational activities. Exhibit No. [BP-6] presents the estimated bill impacts on residential 1,000 kWh/month bill. Exhibit No. [BP-7] presents a summary of JEA's proposed DSM goals. Exhibit No. [BP-8] presents a comparison of JEA's current DSM programs to JEA's proposed DSM program offerings.

Q. How is JEA governed?

A. JEA is a municipal electric utility governed by a Board of Directors consisting of seven members. Four members are nominated by the City of Jacksonville City Council president and confirmed by the City of Jacksonville, City Council, and three members are appointed by the Mayor of the City of Jacksonville and confirmed by the City of Jacksonville City Council. The Board of Directors sets the rates and policies governing JEA's operations. The JEA operating budget requires City of Jacksonville City Council approval. JEA's board meetings are open to the public and ratepayers are permitted to participate in board meetings. JEA's Board of Directors sets policies consistent with the best interest of JEA's customers and community.

Q. Please describe JEA's service territory.

A. JEA is the municipal electric utility provider for the City of Jacksonville and portions of Clay, and St. Johns Counties.

Q. Please describe the demographics of JEA's customer base.

A. JEA serves approximately 522,000 customers. JEA's customers are approximately 88 percent residential. The U.S. Census Bureau last reported in 2022 that the median household income for Jacksonville was $65,579. More than 41% of Jacksonville's population earn less than the Federal Poverty Level or are considered "Asset Limited, Income Constrained, Employed" (ALICE) households, meaning that they earn more than the Federal Poverty Level, but less than the basic cost of living. This breaks down to 14% of households that live in poverty and 27% of households who live as ALICE.

For the past 10 years JEA has offered the Neighborhood Energy Efficiency Program, which is a neighborhood blitz-style program focused on the direct install of energy and water efficiency measures into the homes of our low-income Customers including efficiency and conservation behavioral best practices. JEA just recently embarked on a new low-income focused deep energy and water efficiency improvement program targeting our highest energy burden Customers across Jacksonville called the Restore, Repair and Resiliency (R3) Program. The end goal is to develop a sustainable program through-out low-income neighborhoods in Jacksonville to help hard-working families reduce energy and water use, lower utility bills and remain in their homes. JEA began with an initial pilot program in late 2022 with a core group of community organizations to provide efficiency upgrades to 15 homes on the Eastside of Jacksonville and will continue to assist 76 homes through the Department of Energy's energy efficiency and conservation block grant.

Q. Please discuss how JEA's loads have changed since the last goal setting in 2019.

A. As reported in our 2023 Ten Year Site Plan, JEA's net energy load (NEL) has increased over the 2018-2022 period at an annual average growth-rate (AAGR) of approximately 0.23 percent. JEA experienced an annual average decrease of approximately 3.61 percent in net firm winter peak demand (mild winter weather experienced in 2022) but an AAGR of approximately 2.26 percent in net firm summer peak demand, since the last potential study was performed. JEA's AAGR over the next 10 years are projected to be approximately 0.66 percent for NEL, 0.55 percent for winter net firm peak demand, and 0.54 percent for summer net firm peak demand.

Q. What are JEA's existing FEECA goals based on?

A. JEA's existing FEECA goals were established during the 2019 FEECA process. In its 2019 Goalsetting Order, the Commission determined that it was in the public interest to continue with the goals set in the 2014 Goalsetting Order. *See* Order No. PSC-2019-0509-FOF-EG. For JEA, those goals were based on a settlement agreement approved by the Commission. *See* Order No. PSC-14-0696-FOF-EU (Attachment A). The settlement agreement recognized the role of the municipal utility's governing body to determine the appropriate level of investment in conservation programs and associated rate impacts. *Id.* at p.64 (Attachment A, p.2 of 6). JEA's existing FEECA goals are presented in Exhibit No. [BP-2].

Q. What cost-effectiveness test or tests are appropriate for setting JEA's goals under FEECA?

A. Section 366.82, Florida Statutes (F.S.), requires the Commission to consider, among other things, the costs, and benefits to the participating ratepayers as well as the general body of ratepayers, including utility incentives and participant contributions. However, Section 366.82 does not dictate which cost-effectiveness test must be used to establish DSM goals. In the 2014 Goalsetting Order (Order No. PSC-14-0696-FOF-EU), the Commission determined that the Participant Test is appropriate for calculating the costs and benefits to the customers participating in the energy savings and demand reduction measures. The Commission further determined that consideration of both the Rate Impact Measure (RIM) and Total Resource Cost (TRC) tests is necessary to reflect the

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benefits and costs incurred by the general body of ratepayers, including utility incentives and participant contributions.

Because the RIM test ensures no impact to customers' rates, it is particularly appropriate in establishing DSM goals for municipal utilities, such as JEA. Local governing is a fundamental aspect of public power. It provides the necessary latitude to make local decisions regarding the community's investment in energy efficiency that best suit our local needs and values. Local decisions are based on input from citizens who can speak out on electric power issues at governing board meetings. Accordingly, as the Commission has recognized in prior proceedings, it is appropriate to set goals based on RIM, but to defer to the municipal utilities' governing bodies to determine the level of investment in any non-RIM based measures. *See* Order No. PSC-14-0696-FOF-EU (Attachment A, p.2 of 6).

Q. In general, how would JEA's lower income customers be affected by increases in utility rates due to the implementation of DSM programs that do not pass the RIM test?

A. Lower income customers, in general, spend a disproportionately higher percentage of their disposable income on electric utility bills than higher income customers. As a result, any increases in electric utility rates resulting from the implementation of DSM measures that do not pass RIM would have a tangible negative impact on utility affordability for the more than 40% of JEA's residential customers that earn less than the Federal Poverty Level or are considered ALICE households that are unable or choose not to participate in DSM programs that decrease their electric consumption sufficiently to offset the increased rates.

Q. Please describe JEA's current FEECA demand-side management programs.

A. Exhibit No. [BP-3] includes a summary of the DSM and conservation programs included in JEA's existing Commission-approved DSM Plan.

Q. What is the historic participation rate of JEA's current FEECA demand-side management programs?

A. Exhibit No. [BP-4] presents the historic participation rates in JEA's current FEECA demand-side management programs.

Q. Please describe the program development process.

A. RI worked collaboratively with JEA on the DSM program development process to develop impacts under three scenarios: (1) potential DSM programs that contribute to proposed DSM goals (Proposed Goals scenario): (2) potential DSM programs that pass the Participant and Rate Impact Measure Tests (RIM-scenario); and (3) potential DSM programs that pass the Participant and Total Resource Cost Tests (TRC-scenario).

Q. What, if any, measures were excluded during the process?

A. The analysis began with the measures included in the technical potential study developed by Resource Innovations as discussed in the direct testimony of Mr. Herndon. This measure list was initially refined for program development for three different scenarios related to DSM goals scenario as follows:

1. Proposed Goals Scenario – measures that passed, or were close to passing, either the TRC or RIM Tests and that passed the Participant Test, as well as measures included in JEA's current DSM programs were prioritized for measure bundling.

Please refer to Exhibit No. [JH-12] of the direct testimony of Mr. Herndon for discussion of how measures may have been excluded.

2. RIM -Scenario – measures that passed the RIM-scenario criteria (pass the RIM and Participant Tests, and payback period of at least 2 years) were included in the measure bundling. Please refer to Exhibit No. [JH-12] of the direct testimony of Mr. Herndon for discussion of how measures may have been excluded.
3. TRC -Scenario – measures that passed the TRC-scenario criteria (pass the TRC and Participant Test, and payback period of at least 2 years) were included in the initial measure bundling analysis. Please refer to Exhibit No. [JH-12] of the direct testimony of Mr. Herndon for discussion of how measures may have been excluded.

Q. What demand-side management goals would result from the use of the Participant and RIM Tests?

A. The demand-side management goals that would result from the use of the Participant and RIM Tests can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") of Mr. Herndon's testimony.

Q. Please provide a breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates for demand-side management goals that would result from the use of the Participant and RIM Tests.

A. The breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") of Mr. Herndon's testimony.

Q. What is the estimated rate impact of the goals resulting from the use of the Participant and RIM Tests on a residential 1,000 kWh/month bill?

A. Exhibit No. [BP-6] presents the estimated bill impacts on residential 1,000 kWh/month bill for goals that would result from the use of the Participant and RIM Tests.

Q. Please describe how free-ridership was addressed in developing the demand-side management goals that would result from using the Participant and RIM Tests.

A. Consistent with prior DSM analyses in Florida, free ridership was reflected by applying a two-year payback criterion, which eliminated measures having a simple payback of less than two years. Please refer to Exhibit No. [JH-12] for discussion on sensitivities (i.e. shorter and longer) to the two-year payback period.

Q. What demand-side management goals would result from the use of the Participant and TRC tests?

A. The demand-side management goals that would result from the use of the Participant and RIM Tests can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") of Mr. Herndon's testimony.

Q. Please provide a breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates for demand-side management goals that would result from the use of the Participant and TRC Tests.

A. The breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") of Mr. Herndon's testimony.

Q. What is the estimated rate impact of the goals developed using the Participant and TRC Tests on a residential 1,000 kWh/month bill?

A. Exhibit No. [BP-6] presents the estimated bill impacts on residential 1,000 kWh/month bill for goals that would result from the use of the Participant and TRC Tests.

Q. Please describe how free-ridership was addressed in developing the demand-side management goals that would result from using the Participant and TRC tests.

A. Consistent with prior DSM analyses in Florida, free ridership was reflected by applying a two-year payback criterion, which eliminated measures having a simple payback of less than two years. Please refer to Exhibit No. [JH-12] for discussion on sensitivities (i.e. shorter and longer) to the two-year payback period.

Q. How were JEA's proposed demand-side management goals developed?

A. JEA's current FEECA programs (as established in the 2019 FEECA process) include residential Energy Audits, residential Solar Water Heating incentives, and residential low-income focused Neighborhood Energy Efficiency (NEE) Program and on the commercial side includes Energy Audits and Prescriptive Lighting incentives. In evaluating our proposed FEECA programs for the current FEECA goal setting (2025-2034) cycle, we have removed both residential and commercial Energy Audits from the portfolio because of its lack of permanency as predominantly a behavioral based measure. In addition, we have removed our Solar Water Heating incentive due to lack of customer interest and participation.

For this FEECA goal-setting process, JEA proposes to fill the gap in savings resulting from the elimination of energy audits, by adding our existing Home Efficiency Upgrades Program, that includes incentives for HVAC, Heat Pump Water Heaters and Ceiling Insulation, and our Energy Efficient Products Program, that includes incentives for Energy Star Clothes Washer, Energy Star Room Air Conditioners and Smart Thermostats, to our FEECA portfolio. We will be continuing the NEE Program and Prescriptive Lighting incentives in the portfolio.

Q. Do JEA's proposed demand-side management goals reflect projected peak demand reductions associated with the demand response programs discussed in Exhibit No __[JH-15] to Mr. Herndon's direct testimony?

A. No. JEA offers interruptible load rates. However, JEA has not included projected peak demand reductions associated with demand response or interruptible load in our proposed goals as the current interruptible rate option for customers is considered behavioral in nature and historically JEA has not had to utilize interruptible load. As such, including peak demand reductions associated with the demand response potential identified for large commercial customers in the RIM and TRC scenarios overlaps with our current interruptible load rate, and would inflate our proposed goals and jeopardize our ability to meet our goals regardless of our continuing efforts to offer demand-side management to our customers.

Q. What are JEA's proposed demand-side management goals?

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A. JEA's proposed demand-side management goals can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") to Mr. Herndon's testimony, and are summarized in Exhibit No. [BP-7] JEA's proposed DSM goals.

Q. Please provide a breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates associated with JEA's proposed DSM goals.

A. The breakdown at the program level with demand and energy savings, program costs and benefits, cost-effectiveness test results, list of measures included, and participation rates associated with JEA's proposed DSM goals can be found in Exhibit No. [JH-15] ("JEA Program Development Summary") of Mr. Herndon's testimony.

Q. What is the estimated rate impact of the JEA's proposed demand-side management goals on a residential 1,000 kWh/month bill?

A. Exhibit No. [BP-6] presents the estimated bill impacts on residential 1,000 kWh/month bill associated with JEA's proposed DSM goals.

Q. Did JEA perform any sensitivities that included costs associated with carbon dioxide emissions?

A. JEA did not perform any sensitivities that included costs associated with carbon dioxide emissions. While there is much speculation on the potential for greenhouse gas emissions regulation, it would be inappropriate to establish DSM goals that would increase customer rates based on yet-to-be defined regulations.

Q. Please describe how free-ridership was addressed in developing JEA's proposed demand-side management goals.

A. Consistent with prior DSM analyses in Florida, free ridership was reflected by applying a two-year payback criterion, which eliminated measures having a simple payback of less than two years. Please refer to Exhibit No. [JH-12] for discussion on sensitivities (i.e. shorter and longer) to the two-year payback period.

Q. Please describe the efforts JEA has made to address customers who rent in program development, including a list of programs they would be eligible to participate in.

A. Renters are known to be a hard-to-reach customer segment because the types of measures the can be implemented by those who rent rather than own their dwellings are limited. However, measures such as Energy Star Clothes Washers and Room Air Conditioners, included in the Energy Efficient Products Program, are portable and may therefore be available to renters depending on their specific rental agreements. In addition, almost all the direct install measures in the Neighborhood Energy Efficiency Program are non-permanent and may be available to renters depending on their specific rental agreements. In general, all customers, including those customers who rent, may benefit from JEA's educational and community outreach initiatives related to demand-side management, conservation, and energy and water efficiency.

Q. How are supply-side efficiencies incorporated in JEA's most recent planning process and how do they impact demand-side management programs?

A. JEA continually monitors the operation of its generating units and determines methods to utilize and/or modify the system in the most efficient manner. A recent example of improvement to the efficiency of supply-side resources is advanced gas path additions and compressor modifications for some of JEA's existing combustion turbines. Improvements to the efficiency of supply-side resources (i.e., lower operating costs) should reduce the cost-effectiveness of DSM programs, all else equal.

Q. How do JEA's proposed goals encourage demand-side renewable energy systems?

A. Resource Innovations fully considered demand-side renewable energy systems and found no cost-effective achievable potential for such systems. Therefore, JEA is not proposing goals associated with demand-side renewable energy systems.

Q How do the programs used to determine JEA's proposed goals compare to JEA's current demand-side management program offerings?

A. Exhibit No. ___ [BP-8] presents a comparison of JEA's current DSM programs to JEA's proposed DSM program offerings.

Q. Does this conclude your testimony?

A. Yes, it does.

C13-3992

(Whereupon, prefiled direct testimony of Bradley E. Kushner was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

JEA

DOCKET NO. 20240016-EG

APRIL 2, 2024

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business address is 4767 New Broad Street, Orlando, Florida 32814.

Q. By whom are you employed and in what capacity?

A. I am employed by nFront Consulting LLC (nFront) as a Manager and Executive Consultant and I am the National Director of nFront's Energy practice.

Q. What are your responsibilities in that position?

A. I oversee management of the financial and business aspects of nFront and work with others in the firm to provide consulting services to clients. My responsibilities include project management and project support for various projects for electric utility clients. These projects include integrated resource plans, power supply studies, power supply requests for proposals, demand-side management/conservation reports, and other regulatory filings.

Q. Please describe nFront Consulting LLC.

A. nFront Consulting is organized into two service practices – Energy and Transmission & Delivery. nFront Consulting's Energy Practice provides advisory services to support our electric industry clients. nFront Consulting assists in the areas of planning, implementing, and managing resources, portfolios, and individual business unit operations. nFront Consulting interacts on behalf of our clients with regulatory, political, and environmental agencies; the financial community; and other professional service providers on national, state, and local levels.

nFront Consulting's Transmission and Delivery Services Practice provides independent transmission consulting, analyses and advisory services to support project financing, acquisitions, development, transmission risk, curtailment and congestion assessments, transmission planning, resource integration, and open access, expert witness and regulatory services.

Q. Please summarize your educational background and professional experience.

A. I received my Bachelors of Science degree in Mechanical Engineering from the University of Missouri-Columbia in 2000 and my Master of Business Administration from Emporia State University in 2013. I have nearly 25 years of experience in the engineering and consulting industry, including experience in the development of integrated resource plans, ten-year-site plans, Demand-Side Management and energy conservation plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include JEA, Florida Municipal Power Agency, Kissimmee Utility Authority, Orlando Utilities Commission (OUC), Lakeland Electric, Gainesville Regional Utilities (GRU), Reedy

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Creek Improvement District, Tampa Electric Company, and the City of Tallahassee. I have performed production cost modeling, economic analysis, and related support for six electric power plant need determination petitions filed on behalf of Florida utilities and approved by the Florida Public Service Commission (FPSC). I have also testified before the FPSC in Need for Power and Florida Energy Efficiency and Conservation Act (FEECA) Goal-Setting proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to discuss how JEA's load forecast was developed and the methodology used to develop the avoided capacity costs that were provided to Resource Innovations for use in their analyses of DSM measures for JEA. I will also discuss JEA's fuel forecasts used in the production cost modeling that formed the basis for the avoided energy costs provided to Resource Innovations.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. [BEK-1] is a copy of my resume. Exhibit No. [BEK-2] summarizes the avoided unit costs.

Q. How was JEA's load forecast developed?

A. The JEA load forecast used for purposes of calculating the avoided costs provided to Resource Innovations is based on the load forecast reflected in JEA's 2023 Ten-Year Site Plan, the most recent Ten-Year Site Plan available at the time the analysis began.

The load forecast includes forecasts of seasonal peak demands and annual net energy for load and accounts for interruptible load and the impacts of demand-side management and plug-in electric vehicles. JEA uses the National Oceanic and Atmospheric Administration (NOAA) Weather Station – Jacksonville International Airport for the weather parameters, Moody's Analytics economic parameters for Duval County, projections of residential and commercial customers. JEA's load forecast uses 10 years of historical data, allowing JEA to capture recent trends in customer behavior and energy efficiency and conservation in the actual data that is used in developing projected peak demand and energy requirements.

Additional information related to JEA's load forecast is included in JEA's 2023 Ten-Year Site Plan.

Q. How was the timing of avoidable capacity additions determined?

A. Based on JEA's current load forecast and available generating resources, JEA is anticipated to require additional capacity to maintain a 15 percent reserve margin beginning in 2030. For the anticipated capacity requirements beginning in 2030, it has been assumed that JEA would install a new advanced-class combined cycle at the existing Greenland Energy Center (GEC). JEA has made no commitments to this new combined cycle, and for purposes of this docket, it is considered avoidable capacity and used to develop the avoided capacity costs provided to Resource Innovations for use in their analyses of DSM measures for JEA.

Q. How were capital costs for the additional capacity calculated?

A. The capital cost for the new advanced-class combined cycle was based on estimates used by JEA for resource planning activities and included in Schedule 9 of JEA's 2023 10-Year Site Plan, which presents the estimated in-service year (i.e. 2030) capital cost inclusive of escalation and costs for interest during construction. The estimated in-service year capital cost was multiplied by a fixed charge rate to determine a levelized installed capital cost, which was divided by the output of the combustion turbine to develop a levelized installed capital cost per kW. Adjustments were made to account for the capital cost per kW during summer and winter seasons, given the expected difference in capacity of the advanced-class combined cycle for summer and winter.

Q. How were fixed operating and maintenance (O&M) costs for the additional capacity calculated?

A. The fixed O&M cost for the new advanced-class combined cycle was based on estimates used by JEA for resource planning activities and included in Schedule 9 of JEA's 2023 10-Year Site Plan, which presents the estimated in-service year (i.e. 2030) fixed O&M cost. The fixed O&M costs were escalated to nominal dollars at a 3.0 percent annual escalation rate.

Q. Please discuss how the total avoided costs per kW were calculated.

A. Total avoided costs per kW were calculated by adding the avoided capital costs per kW to the avoided fixed O&M costs per kW. The avoided costs per kW are presented in Exhibit No. [BEK-2].

Q. Please discuss the base case fuel forecast.

A. JEA's generating units utilize a diverse mix of fuels, including natural gas, biomass, petroleum coke, and fuel oil. The base case fuel forecast used for purposes of calculating the avoided energy costs provided to Resource Innovations is based on the fuel price forecasts reflected in JEA's 2023 Ten-Year Site Plan, the most recent Ten-Year Site Plan available at the time the analysis began. The natural gas price projections are based on short-term NYMEX price projections and longer-term price projections are based on escalation rates from the U.S. Energy Information Administration's Annual Energy Outlook 2022 (AEO2022) and include costs for delivery to JEA's generating units. Coal price projections are based on short-term NYMEX Argus-McCloskey price projections and longer-term price projections are based on escalation rates from the AEO2022 and include costs for delivery based on historical transportation costs. Projected prices for petroleum coke are based on historical price differences between JEA's coal and petroleum coke prices. Fuel oil price projections are based on short-term NYMEX price projections and longer-term price projections are based on the AEO2022.

Additional information related to JEA's fuel price projections is included in JEA's 2023 Ten-Year Site Plan.

Q. Did JEA consider high and low fuel price sensitivities?

A. Yes. In addition to the base case fuel price forecasts, JEA considered high and low fuel price sensitivities. The high and low fuel price sensitivity projections provide a band of plus/minus 25 percent around the base case fuel price projections. This high and low band is consistent with what JEA used in the 2019 FEECA goal-setting process.

Q. How were energy costs for each of the cases previously identified in your testimony developed?

C12-3974

A. Under my direction and supervision, PLEXOS, an industry accepted production cost model, was used to perform production cost modeling of its electric generating system, taking into account JEA's generating resources, the avoided unit, load forecast, and the base fuel price projections discussed previously in my testimony.

The resulting energy costs were taken from the PLEXOS output and include fuel as well as non-fuel variable O&M costs associated with dispatch of JEA's resources to meet forecast system demand requirements. The PLEXOS output was provided for use in the economic analysis.

Q. Were energy costs developed for each of the fuel price cases discussed previously in your testimony?

A. Yes. The energy costs developed using the base case fuel price projections were increased by 25 percent for the high fuel sensitivity and decreased by 25 percent for the low fuel sensitivity.

Q. Does this conclude your testimony?

A. Yes, it does.

C12-3974

IN RE: COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS FOR ORLANDO UTILITIES COMMISSION, DOCKET NO. 20240017-EG

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF ORLANDO UTILITIES COMMISSION

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Bradley E. Kushner, and my business address is 4767 New Broad St., Orlando, Florida 32814.

Q. By whom are you employed and in what capacity?

A. I am employed by nFront Consulting LLC ("nFront") as a Manager and Executive Consultant and I am the National Director of nFront's Energy practice.

Q. Please describe your duties and responsibilities in that position.

A. I oversee management of the financial and business aspects of nFront and work with others in the firm to provide consulting services to clients. My responsibilities include project management and project support for various projects for electric utility clients. These projects include integrated resource plans, power supply studies, power supply requests for proposals, demand-side management/conservation reports, and other regulatory filings.

Q. Please summarize your educational background and your employment experience.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Missouri-Columbia in 2000 and my Master of Business Administration degree from Emporia State University in 2013. I have nearly 25 years of experience in the electric utility consulting industry, including experience in the development of integrated resource plans, ten-year site plans, demand-side management ("DSM") and energy conservation plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include JEA, Florida Municipal Power Agency, Kissimmee Utility Authority, Orlando Utilities Commission ("OUC"), Lakeland Electric, Gainesville Regional Utilities, Reedy Creek Improvement District, Tampa Electric Company, and the City of Tallahassee. I have performed production cost modeling, economic analyses, and related support for six electric power plant need determination petitions filed on behalf of Florida utilities that were approved by the Florida Public Service Commission ("PSC"). I have testified before the PSC in power plant need determinations and Conservation Goals proceedings.

Q. Please summarize your experience relating to energy conservation and electric system planning.

A. I have worked extensively on electric system planning and energy conservation projects over the past 24 years. Of particular relevance to my testimony in this case, I have prepared the Ten-Year Site Plans ("TYSPs") for OUC and have also prepared OUC's Annual Conservation Reports on Demand-Side Management and Conservation Programs since the early 2000s. I have also provided testimony supporting the petitions of OUC and JEA in prior dockets before the Commission for setting these utilities' energy conservation and demand reduction goals pursuant to the Florida Energy Efficiency and Conservation Act ("FEECA"), which is set forth in Sections 366.80 through 366.82, 366.83, and 403.519 of the Florida Statutes. These goals are commonly referred to as the "FEECA Goals" for the six Florida utilities that are subject to FEECA: Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company, OUC, JEA, and Florida Public Utilities Company.

Q. Please summarize your experience testifying in regulatory proceedings.

A. I have filed testimony and testified on many occasions before utility regulatory commissions, including testimony before the PSC in the following proceedings:

1. 2009, 2014, and 2019 FEECA Goals Dockets for OUC and JEA (Docket Nos. 20080412-EG, 20080413-EG, 20130204-EG, 20130203-EG, 20190019-EG, and 20190020-EG);
2. Gainesville Renewable Energy Center (GREC) need determination (Docket No. 20090451-EM);
3. Greenland Energy Center need determination (Docket No. 20080614-EM);
4. Cane Island Power Park Unit 4 need determination (Docket No. 20080253-EM);
5. Treasure Coast Energy Center Unit 1 need determination (Docket No. 20050256-EM); and
6. Stanton Energy Center Unit B need determination (Docket No. 20060155-EM).

I have also testified in similar proceedings on system planning issues in South Carolina.

Q. Are you testifying as an expert in this proceeding? If so, please state the area or areas of your expertise relevant to your testimony.

A. Yes. I am providing both factual and expert testimony regarding OUC's avoided generating resource costs, fuel price and energy cost projections, and carbon dioxide ("CO_2") compliance cost projections.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. ___ [BEK-1] Resumé of Bradley E. Kushner

Exhibit No. ___ [BEK-2] Summary of Avoided Unit Costs; and

Exhibit No. ___ [BEK-3] Carbon Regulation Compliance Costs.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I have been engaged by OUC to provide information in support of OUC's analyses of the cost-effective potential of DSM measures and programs related to OUC's proposed FEECA Goals for the 2025 through 2034 period that are to be established in this docket. For clarity, in these proceedings, DSM measures and programs include energy efficiency, demand reduction, and demand-side renewable energy measures and programs. Specifically, my testimony addresses OUC's avoided capital and operating cost information for future power supply resources, OUC's projected energy costs, and estimated costs associated with potential CO_2 regulations or similar requirements. These projections were furnished to Resource Innovations, Inc. ("RI") and used in RI's analyses of the cost-effective potential for energy conservation, peak demand reductions, and demand-side renewable energy resource development for OUC, and in the cost-effectiveness evaluations of potential DSM measures and programs that form the basis for OUC's proposed goals pursuant to FEECA. (RI recently merged with Nexant, Inc., the consulting firm that performed these same functions for the FEECA Utilities in the 2019 FEECA Goals Dockets.)

Q. What issues do you address in your testimony?

A. Relative to the issues identified in Appendix A to the PSC's Order Establishing Procedure, Order No. PSC-2024-0022-PCO-EG ("OEP"), my testimony relates to and supports OUC's testimony and positions on Issues 1, 2, 3, 4, 5, 7, and 8.

Q. Please summarize the main conclusions of your testimony.

A. OUC has based its proposed FEECA Goals on sound analyses of the cost-effective potential of available DSM measures and programs. My testimony supports OUC's use of a 100 MW Battery Energy Storage System ("BESS") with an in-service date of 2027 as the appropriate generating resource in OUC's plans upon which to base considerations of capital cost savings that could be realized through the implementation of DSM programs. My testimony also supports the use of OUC's hourly marginal energy costs evaluated over the period 2025 through 2054 as the appropriate basis to evaluate energy costs that could be avoided by DSM programs, and also estimates of potential costs of compliance with carbon regulatory measures that may be implemented over that same time period. In this context, the capital costs, energy costs, and carbon compliance costs that may be saved by DSM programs are commonly referred to as "avoided costs," and these estimates are used in evaluating the cost-effectiveness of potential DSM programs.

In summary, OUC's proposed FEECA Goals are based on sound, appropriate estimates of the cost savings that the programs that OUC is proposing to meet its FEECA Goals would yield, and accordingly the PSC should approve OUC's proposed FEECA Goals.

III. OUC'S AVOIDED GENERATING CAPACITY COSTS

Q. Please describe OUC's plans for adding electric generating capacity, including both the timing and type or types of OUC's planned generation additions over the period 2025 through 2054.

A. OUC's 2024 Ten Year Site Plan (TYSP), being filed contemporaneously with OUC's petition, testimony, and exhibits in support of its FEECA Goals, indicates that OUC plans to obtain substantial amounts of solar generating capacity and battery energy storage capacity over the 2024-2033 planning period covered by OUC's TYSP. More specifically, OUC plans to obtain through power purchase agreements ("PPAs") approximately 1,267 megawatts of solar generating capacity (MW alternating current, or MWac, nameplate rating) over the period December 2024 through June 2033, and 600 MW of BESS capacity over this period. OUC will obtain additional capacity from the Osceola Generating Station, which is comprised of three separate combustion turbine generating units owned by OUC, in 2025 when two of the turbines are returned to service upon completion of necessary maintenance and transmission system upgrades. To complete the picture of OUC's generation plans, OUC expects to place its oldest coal-fired power plant, Stanton Unit 1, in cold shutdown no later than 2025. In practical terms, this represents Stanton Unit 1 being taken out of service; OUC does not plan to generate electricity using coal after 2027, when Stanton Unit 2 will be converted to burn only natural gas. With these additions and retirements, OUC will have sufficient generating resources, including existing assets owned by OUC and purchased power contracts, to meet its projected reserve requirements through 2033.

Although definite decisions have not been made regarding specific generating resource additions beyond 2033, OUC has adopted a goal of reducing its carbon or greenhouse gas emissions to "net zero" by 2050. To achieve this goal, OUC's plans are to meet the future power supply needs of OUC's customers with expanded solar capacity, expanded battery energy storage capacity, DSM and energy efficiency programs, and potential, but not yet specifically identified, purchases of zero-carbon-emissions power.

Q. Does OUC have any generating capacity costs, including either or both self-owned generation additions or power purchase agreements, over the

period 2025 through 2034, i.e., the ten-year time horizon for the goal-setting process in this docket, that could be avoided by DSM programs?

A. Yes. The next generating resource in OUC's plans that could be avoided by DSM programs is a 100 MW BESS unit with a projected in-service date of June 2027. Accordingly, the capital costs of this BESS unit are the appropriate avoided capital costs to be used in the cost-effectiveness analyses of potential DSM programs and measures. The projected annual revenue requirements associated with the BESS unit are presented in my Exhibit No. ____ [BEK-2].

IV. OUC'S ENERGY COSTS AND FUEL PRICE PROJECTIONS

Q. Please describe OUC's energy costs over the period 2025 through 2034.

A. OUC's energy costs over the analysis period used in the cost-effectiveness analyses prepared by RI were prepared under my supervision and direction. The GenTrader® production cost simulation model was used to produce optimized, least-cost generation projections based on the assumed fuel prices and reasonable assumptions regarding unit performance and availability for OUC's generating resources. GenTrader® is a widely used, proprietary power generation production cost model developed by Power Costs, Inc. that optimizes a utility's power production over a defined time period based on available generation units with defined characteristics together with the utility's loads, fuel prices, fuel positions, power contracts, and fuel supply transportation constraints.

OUC's projected natural gas prices are based on a combination of New York Mercantile Exchange ("NYMEX") futures prices for natural gas and projections provided by PIRA Energy Group ("PIRA"), adjusted for delivery to OUC's delivery points. OUC used 100% NYMEX projections through September 30, 2026, projections based on a 50/50 average of NYMEX and PIRA from October 1, 2026 through September 30, 2028, and projections based entirely on those provided by PIRA Energy Group for the remainder of the study period.

OUC's projected coal prices are based on projections by Energy Ventures Analysis, Inc. ("EVA") for use by OUC as well as recent offers from coal suppliers of Illinois Basin coal.

Q. In your opinion, are the energy cost projections furnished to and used by RI in its analyses of OUC's FEECA Goals and proposed programs appropriate for this purpose?

A. Yes, these energy cost projections are appropriate and as accurate as could reasonably be expected for projections over the analysis period for FEECA Goals potential. OUC's fuel price projections, which represent key foundational input data for any long-term power cost production simulation, are based on reputable, recognized, and widely used industry sources, NYMEX, PIRA, and EVA. OUC's production cost model is GenTrader®, a widely used and recognized power production cost model. Finally, OUC's unit-specific characteristics and load forecasts used in the GenTrader® power cost simulations are the same, continuously vetted input data that OUC uses for its TYSPs. I have responsibility for compiling and reviewing the data and information presented in OUC's TYSPs, and I also review OUC's load forecasts and unit specifications as part of my TYSP work. Accordingly, based on my direct and continuous familiarity with this information, as well as my experience with similar information for other utilities, it is my strong opinion that these projections are consistent with industry standards and fully appropriate for OUC's planning purposes and for RI's cost-effectiveness analyses of DSM potential.

Q. Did OUC and RI utilize any sensitivity cases of projected fuel prices in their analyses of economic and achievable conservation potential for OUC?

A. Yes. OUC developed sensitivity cases that reflect energy costs that are 25 percent higher and 25 percent lower than those associated with the base case fuel price projections. RI performed sensitivity analyses for the cost-effectiveness of potential DSM measures and programs considered by OUC using the same plus-minus 25 percent sensitivities.

Q. Are there any noteworthy features of OUC's generation plans that are relevant to the issues to be considered by the PSC in this case?

A. Yes. FEECA is to be applied to promote the efficient use of electricity and natural gas and to promote the use of renewable energy. In this regard, the PSC should note two particular features of OUC's generation plans.

First, OUC plans to phase out its coal-fired generation completely by 2027, when Stanton Unit 2 will be converted to burn natural gas; Stanton Unit 1 will be placed in cold shutdown in 2025, and OUC does not plan to generate electricity using coal after the Stanton Unit 2 conversion in 2027. The conversion of Stanton 2 to burn natural gas will result in reduced environmental emissions, including emissions of CO_2.

The second noteworthy feature of OUC's long-term energy production and cost projections is that solar generation will provide an increasing share of OUC's electricity supply, consistent with OUC's adopted goal to achieve "net zero" greenhouse gas emissions by 2050. In 2033, OUC expects that more than 50 percent of the electricity that OUC supplies to its customers will come from renewable resources, and this does not include the meaningful and growing amounts of customer-owned solar power already providing power in OUC's service area. Although the impacts become more pronounced after the 2025-2034 FEECA Goals period at issue in this proceeding, OUC's use of renewable energy to meet its customers' needs is fully consistent with FEECA, and correspondingly, OUC's use of fossil generating fuels will continue to decline through and beyond the current FEECA Goals period, also fully consistent with FEECA's purposes.

V. OUC'S CONSIDERATION OF CARBON REGULATORY COMPLIANCE COSTS

Q. Did RI's and OUC's analyses of the cost-effectiveness of potential energy conservation and demand reduction measures and programs include consideration of potential costs of complying with carbon regulations, carbon taxes, or similar government-imposed measures and associated costs? If so, please summarize the assumptions used in any analysis of potential carbon compliance costs or regulations.

A. I should begin my testimony on this point with the qualification that no carbon regulations that would apply or impose costs on OUC yet exist, and thus there is substantial uncertainty surrounding any such programs and their potential impacts on OUC's costs. Such uncertainties include the timing or starting date of any carbon regulatory program, the format or mechanism that such a program or programs might take (e.g., mandatory emission limits, a cap-and-trade allowance system like that applied to regulation of sulfur dioxide, or a carbon tax system), and of course, the levels of any potential allowance costs or carbon emissions taxes.

With that context, pursuant to the procedural requirements in this proceeding, the base case analyzed by RI did not include any carbon compliance costs. However, consistent with FEECA considerations, OUC also engaged RI to prepare a sensitivity analysis that reflects potential carbon compliance costs.

OUC's consideration of potential carbon compliance costs was based on the realistic assumption that there will be no carbon regulations, carbon taxes, or any other mandatory requirement that would impact OUC before 2030, and thus the costs of carbon compliance costs were assumed to be zero for the years 2025 through 2029. Beginning in 2030, OUC incorporated projected carbon compliance costs based on values presented in OUC's 2020 Electric Integrated Resource Plan ("EIRP"). The values from the EIRP were converted to nominal dollars and began at $13.68 per ton in 2030 and escalated to $96.95 per ton in 2054. The annual estimated carbon compliance costs used in RI's analyses are presented in my Exhibit No. ____ [BEK-3].

Q. Do you believe that these are appropriate assumptions? Please explain briefly the impact of these assumptions on the amount of DSM or energy conservation that would be justifiable based on inclusion of these assumptions.

A. Yes, for the following reasons, I believe, and OUC believes, that these assumed carbon compliance cost estimates are appropriate, albeit somewhat aggressive, and that, if anything, they will favor more energy conservation. First, regarding the 2025-2029 period, OUC believes that the assumption of zero costs is reasonable because there are presently no mandatory carbon or greenhouse gas reduction compliance measures, i.e., no mandatory carbon tax nor any mandatory carbon cap-and-trade program, applicable in Florida. Recognizing the value that the Orlando community believes flows from reducing carbon emissions, OUC projects to be a leader in reaching its net-zero goal by 2050, at which point any impacts of mandatory carbon compliance costs on OUC's electric rates would be minimal. Further recognizing the Orlando community's values as well as the uncertainties surrounding potential carbon compliance costs, OUC has assigned fairly aggressive values for purposes of estimating the cost savings from reducing carbon-fueled generation in its avoided marginal fuel cost estimates used in evaluating the cost-effectiveness of DSM measures and programs. In simple terms, the greater the cost savings from conservation, in this case avoided carbon compliance costs, the more conservation will be cost-effective.

VI. CONCLUSIONS

Q. Please state the main conclusions of your testimony.

A. The generating costs, including both capital and fuel costs, upon which OUC's and RI's analyses are based, are sound and appropriate. OUC utilized a sound and widely used production cost model, GenTrader®, and fuel prices developed by widely used and respected analytical companies and resources to develop estimates of fuel prices and generating costs that were used in RI's evaluation of the cost-effectiveness of potential DSM measures. OUC's consideration of potential compliance costs associated with carbon regulations or similar regimes are somewhat aggressive, but if anything, they would tend to result in more energy conservation being deemed cost-effective as compared to more conservative assumptions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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(Whereupon, prefiled direct testimony of Kevin M. Noonan was inserted.)

IN RE: COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS FOR ORLANDO UTILITIES COMMISSION, DOCKET NO. 20240017-EG

DIRECT TESTIMONY OF KEVIN M. NOONAN

ON BEHALF OF ORLANDO UTILITIES COMMISSION

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Kevin M. Noonan, and my business address is Orlando Utilities Commission, Reliable Plaza at 100 West Anderson Street, Orlando, Florida 32801.

Q. By whom are you employed, and in what position?

A. I am employed by the Orlando Utilities Commission ("OUC") as Director of Legislative Affairs.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for developing and implementing OUC's political engagement strategy with state and local elected officials, as well as other key government officials and policymakers. I work towards achieving passage of OUC sponsored legislation while also guiding and advising the organization on other proposed legislation and regulations that may impact OUC. I attend hearings, committee meetings, and council meetings and provide appropriate responses when necessary. I prepare proposed legislative recommendations and advise on processes that may lead to policy development. I work closely with other members of OUC's management and technical personnel on energy policy issues, including conservation and renewable energy matters, and I present testimony and other support as necessary. In this capacity, I testified in the 2019 Goals Dockets on behalf of OUC. I also advise OUC leadership and internal stakeholders on key state and federal legislative and regulatory policy matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Economics from Florida State University, a Master of Science in Urban and Regional Planning from Florida State University, and a Certificate in Management from Rollins College. I am a government relations, metering, sustainability and customer service professional with nearly 30 years of experience in developing innovative government outreach and customer focused programs. In my career with OUC, my work on customer service and sustainability has included more than four years (2009-2013) of service as OUC's Director of Conservation & Renewables. In this role, I developed and implemented all of OUC's new customer conservation and education programs, including electric demand-side management and energy conservation efforts. My work included managing customer rebates and efficiency incentives for residential and commercial customers, including solar thermal and solar photovoltaic ("PV") rebate programs, as well as coordinating with other OUC departments on large-scale renewable energy projects. Exhibit No. ___ [KMN-1] is a copy of my current resumé.

Q. **Are you testifying as an expert in this proceeding? If so, please state the area or areas of your expertise relevant to your testimony.**

A. I am testifying both as to factual information regarding OUC and also as an expert on energy conservation policy issues, including the energy conservation and demand reduction goals proposed by OUC pursuant to FEECA. These goals are referred to in my testimony as OUC's "FEECA Goals."

Q. **Have you previously testified before the Florida PSC?**

A. Yes. I testified on behalf of OUC in support of OUC's goals proposals in the 2019 Goals Docket, Docket No. 20190019-EG.

Q. **Are you sponsoring any exhibits to your testimony?**

A. Yes. I am sponsoring the following exhibits:

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Exhibit No. ___ [KMN-1] Resumé of Kevin M. Noonan;

Exhibit No. ___ [KMN-2] OUC's 2024 Annual Conservation Report: Demand-Side Management and Conservation Programs Offered in Calendar Year 2023

Exhibit No. ___ [KMN-3] OUC's Proposed Numeric Demand and Energy Goals, 2025-2034;

Exhibit No. ___ [KMN-4] OUC's Existing and Proposed FEECA Programs; and

Exhibit No. ___ [KMN-5] Estimated Bill Impacts per 1,000 kWh Residential Service.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in these proceedings?

A. I am testifying on behalf of OUC in Florida PSC Docket No. 20240017-EG, which is titled In re: Commission Review of Numeric Conservation Goals for Orlando Utilities Commission. This docket is one of six essentially identical dockets, consolidated for hearing and administrative purposes, in which the PSC will establish goals for OUC and five other electric utilities that are subject to the Florida Energy Efficiency and Conservation Act ("FEECA," which consists of Sections 366.80 through 366.82, 366.83, and 403.519 of the Florida Statutes) for the goal-setting period 2025 through

2034. These FEECA Goals will include goals for improving energy efficiency, controlling and reducing the growth of electric energy consumption, reducing the growth of weather-sensitive peak electricity demands, and encouraging the development of demand-side renewable energy resources. The other utilities currently participating in these Dockets are Duke Energy Florida ("DEF"), Florida Power & Light Company ("FPL"), Florida Public Utilities Company ("FPUC"), JEA (formerly named Jacksonville Electric Authority), and Tampa Electric Company ("Tampa Electric" or "TECO"), and I refer to this group, including OUC, as the "FEECA Utilities" in my testimony.

My testimony describes OUC, our service area and unique customer base, our existing generation, transmission, and distribution facilities, and our load and usage characteristics.

My testimony presents OUC's proposed FEECA Goals and the programs that OUC is proposing to meet those goals, as well as the scenarios of programs that would pass the Rate Impact Measure Test ("RIM Test") and the Total Resource Cost Test ("TRC Test") as prescribed by the PSC's rule provisions implementing the conservation goals requirements of FEECA (Rule 25-17.0021, Florida Administrative Code, abbreviated as the "Goals Rule") as that rule was revised in 2023. The first step in the goals development process was the estimation of the full Technical Potential for

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energy efficiency (conservation) savings, peak demand reductions, and demand-side renewable energy measures for OUC. The Technical Potential is a high-level estimate of the maximum possible amounts of demand reductions and energy savings that could be realized if every conceivable measure were implemented by every customer who could physically do so, without considering implementation or installation costs or any other real-world constraints. For these FEECA Goals proceedings, OUC joined the other FEECA Utilities in engaging Resource Innovations, Inc. ("RI") to develop estimates of the Technical Potential for DSM savings for all of the FEECA Utilities. RI's analyses show that there is significant Technical Potential for summer and winter peak demand reduction (measured in megawatts, or "MW" and abbreviated as "DR") and energy reduction (measured in gigawatt-hours, or "GWH" and abbreviated as "EE," for Energy Efficiency) from DSM measures in OUC's service area.

Pursuant to the PSC's Goals Rule as amended in 2023, OUC also engaged RI to identify measures that would cost-effectively reduce summer and winter peak demands and reduce total energy consumption, and then to assist OUC in "bundling" measures into programs that would meet those numeric goals consistent with FEECA's requirements that a utility's FEECA Goals must be cost-effective to participating customers and to the utility's general body of ratepayers as a whole. As discussed in more detail later in my testimony, the programs that OUC is proposing to meet its goals in these proceedings include nearly all of the measures in OUC's current DSM programs; one measure, Solar Thermal Water Heating, will be discontinued due to low participation, and one measure, Smart Thermostats for both Residential and Commercial customers, has been added. The demand and energy savings of the programs were then translated into the numeric summer and winter peak demand reduction goals and energy reduction goals as required by the Goals Rule.

Collectively, my testimony and exhibits, together with the testimony and exhibits of Jim Herndon, the principal consultant for RI's work, and Bradley Kushner, a consultant to OUC employed by nFront Consulting, Inc., describe OUC's and RI's collaboration in the analyses that support OUC's proposed FEECA Goals and address all of the specific issues and requirements set forth in the PSC's Order Establishing Procedure for these proceedings.

Q. Please summarize the main conclusions of your testimony.

A. OUC continuously evaluates and implements DSM measures, including measures that reduce peak demands, reduce energy consumption, and encourage demand-side renewable energy measures, as well as supply-side energy efficiency conservation measures. OUC's track record of DSM and renewable energy achievements is substantial and excellent.

Balancing all relevant factors, including the results of the analyses required by the PSC's Goals Rule, OUC's overall energy goals, the needs and desires of the Orlando community for robust energy conservation efforts, the unique characteristics of OUC's customer population, potential rate impacts, customer impacts, and measure- and program-specific factors, OUC is proposing FEECA Goals in this proceeding that are based primarily on a set of reasonably achievable and cost-effective conservation and demand reduction measures that are included in OUC's existing DSM programs. OUC;s proposed FEECA Goals are summarized in the following table.

Goal	2025	2030	2034
Summer KW Savings	590	580	890
Winter KW Savings	560	730	810
Energy (NEL) Savings (MWH)	4,242	5,760	6,382

For reference, OUC's 2024 Energy Savings goal is 1,370 MWH.

As with most policy and program decisions, OUC's proposed Goals require a difficult balancing of competing policies. Specifically, while as a matter of basic policy, OUC continues its longstanding support for the policy basis of the Rate Impact Measure Test ("RIM Test"), which is to avoid cross-subsidization of customers who participate in a utility's DSM programs by the utility's customers who are unable or choose not to participate, OUC's proposed FEECA Goals include programs and measures that do not pass the RIM Test. This is not new, in fact, it is fully consistent with OUC's energy conservation record for the past 30 years: recognizing the values and desires of the Orlando community and the citizens whom OUC serves, and the important public interest benefits flowing to Orlando, the entire state of Florida, the U.S., and the world from using energy as efficiently as possible, OUC's goals and conservation achievements have historically far exceeded those that would flow from a strict application of the RIM Test. OUC's proposed FEECA Goals in this case follow this policy. Having said that, in OUC's continuing efforts to serve the best interests of the Orlando community, as discussed later in my testimony, many of the specific measures and programs included in OUC's proposed FEECA Goals do pass the TRC Test.

In conclusion, taking full account of the unique characteristics of OUC's customer base and the values of the greater Orlando community whom we serve, OUC is proposing FEECA Goals that will provide meaningful reductions in summer and winter peak demands and total energy use over the 2025-2034 period. These energy savings will complement and multiply the tremendous environmental benefits resulting from OUC's commitment to reduce overall greenhouse gas emissions to net-zero levels by 2050. OUC's proposed FEECA Goals are consistent with our long history

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of doing far more than the minimum required in order to address the complex challenges of balancing the competing goals of minimizing customer bills, meeting the needs of rental customers and low-and-middle-income customers, and serving our citizens' demands for meaningful progress toward promoting environmental quality, including reductions in greenhouse gas emissions to meet the global challenge of climate change.

When approved by the PSC, OUC's efforts will, as they have for decades, result in significant energy conservation and renewable energy achievements for the benefit of our customers, the Greater Orlando community, and Florida as a whole. The PSC should approve OUC's proposed FEECA Goals.

<u>III. OUC & OUR SYSTEM</u>

Q. Please describe the Orlando Utilities Commission and its governing structure.

A. OUC is governed by a five-member governing board known as the OUC Commission. Commissioner candidates serve based on staggered 4 year terms and as they roll off of the OUC Commission, new candidates are nominated by the City of Orlando Nominating Board, approved by the OUC Commission, and ratified by the City of Orlando City Council. All members must be OUC customers, and at least one member must live outside the

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Orlando city limits. The Mayor of Orlando serves as an ex officio voting member of the OUC Commission; the other four members may serve up to two four-year terms. All members of the OUC Commission serve without compensation.

The OUC Commission sets the rates and establishes the policies governing OUC's service and operations. OUC's board meetings are open to the general public and customers are permitted to participate in OUC Commission meetings in accordance with Chapter 286, Florida Statutes ("F.S.").

Q. Please describe OUC's service area and physical operations, including OUC's generation and other power supply resources, transmission system, and distribution facilities.

A. OUC's retail electric service area covers approximately 419 square miles and includes the City of Orlando, portions of unincorporated Orange County, and portions of Osceola County, including the service area of the City of St. Cloud's electric utility system. OUC and the City of St. Cloud ("St. Cloud") are partners in an interlocal agreement under Chapter 163, F.S. (the "Interlocal Agreement"), pursuant to which OUC serves the entire retail electric service requirements of St. Cloud within the City of St. Cloud's electric utility service territory. In addition, OUC and operates and maintains

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its electric generation, transmission and distribution systems. While St. Cloud is a legally separate municipal electric utility, consistent with our obligations pursuant to the Interlocal Agreement, OUC treats the St. Cloud load and customers as part of OUC's retail obligations for planning and energy conservation purposes.

OUC's generating facilities include owned interests totaling approximately 669 MW of simple cycle combustion turbine ("CT") and 476 MW of combined cycle ("CC") capacity fueled by natural gas, 663 MW of capacity fueled by coal, and 60 MW of nuclear generating capacity.

Additionally, OUC has a firm power purchase commitment ("PPA") for approximately 340 megawatts ("MW") of the Stanton A gas-fired combined cycle unit through December 2031, and an additional 87 MW commitment through 2028; this capacity is actually owned by NextEra Energy. OUC also has two contracts to purchase solar power from existing facilities at the Stanton Energy Center, one for 6 MW and one for 13 MW. In addition, OUC has contracts in place to purchase 18 MW of landfill gas capacity and utilizes additional landfill gas to offset coal generation from Stanton Energy Center Units 1 and 2.

OUC's transmission system includes 31 substations interconnected through approximately 339 miles of 230 kV and 115 kV transmission lines. OUC has a total of 31 interconnections with FPL, DEF, KUA (Kissimmee

Utility Authority), KUA/FMPA (Florida Municipal Power Agency), Lakeland Electric, Tampa Electric, and the Central Florida Tourism Oversight District. Additionally, through the Interlocal Agreement, OUC is responsible for planning, operating and maintaining St. Cloud's seven (7) substations, 71 miles of 230 kV and 69 kV transmission lines, and seven (7) interconnections.

OUC's distribution system includes more than 2,000 circuit miles of distribution lines, excluding service laterals, and appurtenances including transformers, switchgear, capacitors, and protective devices to serve our customers.

Q. Please describe OUC's customer base and OUC's current load and usage characteristics.

A. OUC currently serves approximately 275,000 electric customer accounts, including approximately 242,000 electric residential customers, 28,000 electric commercial customers, 5,100 electric industrial customers, a small number of customers to whom OUC provides street and highway lighting service, and a similarly small number of other public authorities to which OUC provides service. (These values include customers served by OUC in the City of St. Cloud.)

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Approximately 43 percent of OUC's residential customers (including those in St. Cloud) live in multi-family residences, and most of these are rental units. Additionally, a significant number of single-family residences served by OUC are renter-occupied. Approximately 33 percent of OUC's residential customers have household incomes less than $50,000, which is approximately 1.6 times the Federal Poverty Level for a family of four in 2024. (For reference, households qualify for food stamps if their household income is up to 2.0 times the Federal Poverty Level.) The fact that so many of OUC's residential customers are low-income and renters presents special challenges to the effective implementation of DSM measures and programs for OUC, and particularly for this potential target population. Briefly, low-income customers simply do not have the discretionary income to pay the customer's cost to participate in a DSM program, and renters have little, if any, control over such expenditures and investments by their landlords. Even if renters have sufficient discretionary income and the ability to make efficiency improvements, they have little incentive or opportunity to do so since they do not own the property. These factors significantly limit the potential for OUC to implement residential DSM measures and programs. Tenant-occupied commercial properties experience the same dilemma when it comes to investing in energy efficiency improvements to property they do not own.

The average usage per OUC residential customer is slightly less than 1,000 kWh per month, which is widely considered the "typical" consumption level for residential electric customers in Florida. In 2023, the average was 983 kWh per month, and the forecast value for 2024 is 936 kWh per month. Of course, actual values will vary with weather conditions and other variables.

Q. Please describe OUC's current and projected retail and total peak demand and energy consumption.

A. OUC is a summer-peaking utility. OUC's 2023 net firm system peak demand of 1,792 MW occurred in August 2023 and included St. Cloud as well as wholesale sales to Vero Beach, Winter Park, Lake Worth, Bartow, and FPL. OUC's 2023 peak retail demand (including St. Cloud) was approximately 1,551 MW. OUC's 2023 total retail sales (consisting of sales to residential, commercial, and industrial customers) were approximately 7,155 Gigawatt-hours ("GWH"), and our Net Energy for Load ("NEL") was approximately 7,972 GWH.

To provide a frame of reference for the goal-setting period through 2034, OUC's most current Ten-Year Site Plan ("TYSP") for 2024 shows that system firm peak demand, including wholesale supply obligations, is projected to increase from 1,746 MW in 2024 to approximately 1,850 MW in 2033. OUC currently projects that it will not have any long-term committed wholesale supply obligations in 2033. OUC's total system NEL is projected to increase from 7,896 GWH in 2024 to approximately 8,994 GWH in 2033. Our retail energy load over the same period is projected to increase from 7,033 GWH in 2024 to about 8,702 GWH in 2033. Our average usage per residential customer account is projected to increase over this period, from about 11,230 kWh per customer per year in 2024 to about 12,610 kWh per customer per year in 2033.

Q. Please summarize OUC's existing DSM programs, goals, and achievements.

A. OUC's existing DSM programs, goals, and achievements are described in my Exhibit No. ___ [KMN-2], OUC's 2024 Annual Conservation Report: Demand-Side Management and Conservation Programs Offered in Calendar Year 2023. In summary, as shown on Table 3-5 of this Report, OUC currently offers a total of seven Residential Programs and seven Commercial/Industrial Programs that contribute to our FEECA Goals, plus energy surveys for both residential customers and commercial/industrial customers. OUC also achieves significant energy savings through programs not included in our FEECA programs and through non-customer-facing programs. OUC's achieved total energy efficiency impacts of approximately

352,000 MWH in 2023, representing approximately 4.93 percent of OUC's retail sales.

Q. Please provide a brief discussion of how the "Base Case" forecast of OUC's customers, winter and summer demands, and energy requirements (Net Energy for Load) was developed.

A. The basis for the projections of OUC's demand and energy requirements that RI used in its analyses were projections from OUC's 2023 Ten-Year Site Plan ("TYSP") and supporting information regarding number of customers and customer usage data. The 2023 TYSP data and information were used by the FEECA Utilities (except for FPUC, which does not file a TYSP) because these data were the best information, and the only comparable information, available during 2023 when RI performed the majority of the Technical Potential analysis. OUC's demand and energy projections in its Ten-Year Site Plans are based on a set of sales, energy, and demand forecast models each year to support its budgeting and financial planning process as well as long-term planning requirements. In preparing the forecasts, OUC uses internal records, company knowledge of the service territory and customers, and economic projections. OUC draws on outside expertise and resources as needed for economic projection data, forecasting software, analysis of end-use equipment saturation and efficiencies, and technical expertise. Outside technical resources include Itron, IHS Markit Ltd., and the National Renewable Energy Laboratory. Additionally, OUC forecasting personnel meet regularly with other utility load forecasting experts to ensure that our efforts are fully informed and consistent with the best information available.

As explained in the testimony of Jim Herndon, RI used OUC's data in developing more detailed estimates of peak demands and energy usage for different segments of the Residential and Commercial/Industrial customer sectors, and then aggregated those to develop projected system peak demands and energy loads, which were then used in analyzing Technical Potential. For OUC, RI used data for the Residential, General Service, and General Service-Demand rate classes.

Q. How does OUC expect its customers need for electric service and its generation system to grow in the future?

A. As OUC's customer population and the Orlando economy grow, OUC's generation system will necessarily have to grow to serve their needs and wants. OUC's 2024 Ten-Year Site Plan projects that over the next ten years, OUC's net energy for load is projected to grow from 7,896 GWH in 2024 to approximately 8,994 GWH in 2033, and our summer peak firm demand is expected to grow from 1,746 MW in 2024 to approximately 1,850 MW in

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2033. For reference, the FEECA Goals to be established for OUC in this proceeding will be set for 2025-2034, subject to further review and potential re-setting in 2029 proceedings; to consider the long-term value of DSM, costs and benefits were analyzed for the 30-year period from 2025 through 2054.

Q. How does OUC expect to meet the needs of its customers and the Orlando community?

A. OUC is one of four utilities in Florida that has adopted a definite goal for reducing its greenhouse gas emissions. OUC's goal is to be "net zero" by the year 2050. We expect to meet this goal through a combination of greatly expanded solar generating facilities, expanded battery energy storage capacity, DSM programs, active promotion of electric vehicles to displace carbon emissions from vehicles, and potential, but as yet not specifically identified, purchases of zero-emissions power.

IV. OUC'S PROPOSED FEECA GOALS FOR 2025-2034

Q. Please summarize OUC's proposed numeric goals for summer and winter peak demand savings and for energy savings for the period 2025 through 2034.

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A. OUC's proposed goals for the 2025-2034 period addressed in this goal-setting proceeding are summarized as follows:

Goal	2025	2030	2034
Summer KW Savings	590	580	890
Winter KW Savings	560	730	810
Energy (NEL) Savings (MWH)	4,242	5,760	6,382

OUC's year-by-year goals for 2025 through 2034 are presented in my Exhibit No. ___ [KMN-3].

Q. Please summarize the process by which OUC's proposed goals were developed.

A. In summary, OUC's goals were developed by first estimating the full Technical Potential for energy conservation and DSM savings. The next step was to identify the measures that would meet the RIM Test and the Participant Test, i.e., the RIM Scenario, and the measures that would meet the TRC Test and the Participant Test, i.e., the TRC Scenario. The results of this step indicated that no Residential measures and no Commercial or Industrial Energy Efficiency ("EE") or Demand-Side Renewable Energy ("DSRE") measures passed the RIM Test. However, a group of four Demand Response measures that could potentially be made available to large (demand greater than 500 kW) commercial and industrial customers did pass the RIM Test. (As explained fully below, OUC is not proposing a goal for such

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measures or a program to implement any of the measures in this proceeding.) Next, RI and OUC considered the results of the TRC Test, including application of the PSC-approved two-year payback screen to address free ridership concerns. This analysis showed that many of the measures in OUC's existing DSM program offerings have passing TRC results based on simplified assumptions, and so OUC and RI collaborated on "bundling" OUC's existing measures that meet the TRC Test into re-defined programs; based on practical considerations, e.g., where a possible measure barely passes the TRC Test with a minimal incentive payment and without any consideration of program administrative costs, or where the administrative costs of establishing a new program were deemed to be excessive, a few measures were eliminated at this stage, and a few new measures were added. Once the portfolio of programs reasonably projected to provide energy conservation savings was identified, OUC and RI reviewed and agreed upon estimated participation rates for those programs; these estimates were based on OUC's experience with its programs and measures and on RI's data library of adoption rates in real-world market settings. Savings per participant for each program for each year of the 2025-2034 period were applied to the estimated participation levels to obtain summer and winter MW savings and NEL savings for the period; these values were then set as

OUC's proposed FEECA Goals, and the programs that would produce these savings are the programs that OUC will propose to meet its FEECA Goals.

A. **<u>OUC's Full Technical Potential DSM Savings</u>**

Q. **Please summarize how OUC'S Technical Potential for demand-side energy conservation and demand reductions was estimated.**

A. OUC joined with the other five FEECA Utilities to engage RI to prepare analyses of the Technical Potential for energy savings and demand reductions for all six FEECA Utilities. The Technical Potential analyses estimated the maximum amount of energy savings and peak demand reductions that could be achieved if every customer technically capable of implementing a measure were to do so, regardless of cost, customer acceptance, or any other constraints or considerations, including availability and cost-effectiveness to either the customer or the utility.

Q. **Please summarize how the Technical Potential for demand-side energy conservation on OUC's system was updated since the 2019 Goals Dockets.**

A. The estimated Technical Potential for OUC is addressed in the testimony and exhibits of Jim Herndon. The Technical Potential estimates were, of course, updated based on OUC's system characteristics and planning estimates as

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reflected in OUC's 2023 TYSP, as well as on Mr. Herndon's and RI's adjustments for changes in other factors such as appliance efficiency standards and building code requirements.

Q. What were OUC's and RI's respective roles in preparing the Technical Potential analyses of DSM measures for OUC?

A. For these analyses, OUC prepared and provided to RI OUC-specific input data needed for these analyses. RI also developed a great deal of input data and program information as part of its engagement with the FEECA Utilities, and RI was responsible for preparing the Technical Potential analyses and corresponding results for DSM measures for OUC.

Q. Are the data and information prepared by OUC and used by RI appropriate and reliable?

A. Yes. The information prepared by OUC and furnished to RI is the same reliable information that OUC uses in making its system planning decisions and in preparing its annual Ten-Year Site Plans and other reports to the PSC.

B. OUC's Proposed FEECA Goals and Programs

Q. After estimating OUC's Technical Potential for conservation savings, how did OUC proceed to develop its FEECA Goals?

A. The Technical Potential analysis identified 119 residential measures and 282 Commercial/Industrial measures that could contribute to energy savings on OUC's system. The next step was to develop the two scenarios of programs required by the PSC's Goals Rule, one scenario including programs that would pass the RIM Test and the Participant Test – the "RIM Scenario" – and another group of programs that would pass the TRC Test and the Participant Test – the "TRC Scenario."

The final step in developing OUC's FEECA Goals was to develop programs that OUC believes, taking account of the potential savings and costs of DSM measures and programs, the unique characteristics of OUC's customer base and the Orlando community, the values and desires of the Orlando community whom we serve, and the public interest generally, will best serve our customers and the public interest of the Orlando community, Florida, and the United States.

Q. How was the RIM Scenario developed?

A. The RIM Test measures the impact of a given measure or program on non-participating customers by measuring the impact on all customers' rates; if the savings from a program are less than the cost shift that results from lower payments by participating customers, the program will have a negative benefit-cost ratio under the RIM Test. This indicates that the utility's non-participating customers are subsidizing the program participants.

After the Technical Potential analysis had identified technically possible DSM measures, the next step was to examine whether any of the technically possible measures were justified based on the simple economic consideration of whether the avoided capacity cost and fuel cost savings outweighed the rate impacts of "lost revenues" on non-participating customers. At this point, no program costs were considered, no real-world considerations relating to marketing and measure adoption by customers, and no considerations of free ridership were included in the analysis. This analysis resulted in zero Residential DSM measures passing the RIM Test; for clarity, no Residential Energy Efficiency measures, no Residential Demand Response ("DR") measures, and no Residential Demand-Side Renewable Energy ("DSRE") measures passed the RIM Test.

One group of potential Demand Response measures or programs applicable to the large demand (greater than 500 kW) segment of commercial and industrial customers did pass the RIM Test; there are four programs (measures) in this group: Automated Demand Response, Critical Peak Pricing, Firm Service Load, and Guaranteed Load Drop Programs. Impact, benefit, and cost information regarding these measures, each of which would provide incentives to large-demand commercial and industrial customers to

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reduce their peak demands, is presented in exhibits to Mr. Herndon's testimony. OUC does not intend to propose goals or a program based on these measures because each program or measure targets the same customer population and their benefits are thus mutually exclusive as between the 4 measures while their startup costs are additive. The startup and first-year cost to implement even one of these programs is significant, i.e., $2 million to $4 million, which would represent a dramatic increase over the costs of OUC's proposed goals and programs. Costs of this magnitude are of particular concern considering uncertainties regarding number of participants and thus actual benefits. OUC plans to evaluate these measures prospectively and to discuss with our customers and other utilities how we may be able to develop a program that will benefit our large customers and OUC's general body of customers as well.

Q. How was the TRC Scenario of DSM measures and programs developed?

A. Applying the TRC Test, the initial economic analysis was a comparison of the avoided capacity cost and fuel savings to the raw hardware costs of measures or programs; this step in the quantitative analysis included no program administrative costs, no incentive payments, no consideration of adoption or participation rates, and no consideration of "free riders."

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Measures that showed a benefit/cost ratio of 1.0 or greater were included for further consideration.

The next step in the quantitative analysis of measures using the TRC Test included the addition of program costs by RI, application of estimated adoption and participation rates (from RI's data library) by potential customers, and the application of a two-year payback screen to address free ridership. These additional factors resulted in a set of measures that passed the TRC Test and the Participant Test. These measures were then "bundled" into programs, which became the TRC Scenario of programs identified for OUC pursuant to the Goals Rule. Demand and energy savings impacts, participation, and cost and benefit information for this TRC Scenario of programs is presented in Mr. Herndon's testimony and exhibits.

Q. Does the TRC Scenario include any Demand Response or Demand-Side Renewable Energy programs or measures?

A. Yes. The TRC Scenario includes the same set of four Demand Response programs discussed above that would, if implemented, be applicable for large-demand commercial and industrial customers. The TRC Scenario results for these programs are also included in the exhibits to Mr. Herndon's testimony. No Demand-Side Renewable Energy measures passed the TRC

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Test, and accordingly, no DSRE programs are included in the TRC Scenario for OUC.

Q. Please explain the "free rider" issue and the payback screen.

A. In this context, a "free rider" is a customer who takes advantage of a utility's DSM program or measure when the customer would have implemented the measure anyway. The "free rider" problem is that the utility's customers, including those that are unable to participate or choose not to participate, pay for the measure unnecessarily. The participating customer is said to get a "free ride" because the customer gets the benefits but only pays a fraction of the program cost through rates as compared to what the customer would have paid for the measure without being incentivized to implement it.

Q. In developing OUC's proposed FEECA Goals, how did RI and OUC address and consider the "free rider" issue, i.e., the fact that some customers would implement a given energy conservation measure even if there were no economic incentive offered for them to do so?

A. OUC and RI followed the analytical framework previously approved by the PSC and evaluated free ridership in three scenarios: a "base case" scenario in which the maximum allowable incentive was determined as the amount necessary to make the measure cost-effective to a participating customer based on a two-year payback to the customer, including the incentive; a shorter free rider exclusion period of one year; and a longer free rider exclusion period of three years.

RI prepared its base case cost-effectiveness analyses using a two-year free-ridership screen, which reasonably assumes that a customer who would experience positive net benefits from a self-financed measure with a simple payback of two years or less would implement the program anyway, i.e., without any utility-provided incentive. RI also prepared free rider sensitivity analyses using a one-year free ridership screen and a three-year screen. Using the shorter screen results in incrementally more participation in utility-incentivized measures and thus more potential conservation, while the longer screen results in less. The base case two-year free ridership screen has been used by the PSC since 1994, and the one-year and three-year sensitivity cases are the same as sensitivities considered in prior FEECA Goals dockets, including those in the most recent 2013-2014 and 2018-2019 cycles.

Q. Do you believe that the two-year payback screen is a reasonable way to address the free rider issue?

A. Yes. The two-year payback screen reasonably assumes that a customer who would realize a simple payback of investment in a DSM measure in two years would implement the measure anyway, and accordingly, the FEECA Utilities

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have applied and the PSC has approved the use of this screen to avoid these unnecessary subsidies. Looked at in simple economic terms, a customer should be willing to invest in a conservation measure that will provide a simple return of 50 percent per year.

Q. How were the costs and benefits to customers who do not participate in a program – i.e., "non-participating customers" or the "general body of ratepayers" developed and estimated?

A. The benefit values of a DSM program or measure to a utility's general body of ratepayers include avoided capacity costs, avoided fuel costs, and potential avoided carbon regulation costs, that result from a measure or program. The costs borne directly by the general body of ratepayers include program administrative costs, including any utility-funded installation costs, and incentive payments to participating customers. The RIM Test includes consideration of potential shifts in revenue or cost responsibility where the payments for electric service by participating customers are greater than the savings that their participation provides. The RIM Test analyses were based on administrative costs furnished by OUC, and also using the program and incentive costs of implementing measures developed and calculated by RI, and on rate and revenue information provided by OUC.

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Q. How did OUC develop the goals that it is proposing in this proceeding?

A. The preceding quantitative analyses identified the Technical Potential for DSM savings and further identified the RIM Scenario and the TRC Scenario of programs that would pass the respective cost-effectiveness tests under the assumptions discussed above. OUC then compared OUC's current DSM program offerings to the measures that passed the TRC Test and considered OUC's overall energy goals, the needs and desires of the Orlando community for robust energy conservation efforts, potential rate impacts, customer impacts, and measure- and program-specific factors to identify the measures that OUC wants to implement over the 2025-2034 period. Generally, OUC decided that it is in the best interests of our customers and our community to continue to offer virtually all of the measures offered through OUC's existing FEECA DSM programs; one new measure, Smart Thermostats for residential and commercial customers, was added and one previously offered measure, Solar Thermal Water Heating, would be discontinued due to low participation.

Q. Please compare the measures included in OUC's proposed programs and goals to the measures that are included in OUC's existing programs.

A. Please refer to my Exhibit No. ____ [KMN-4], which shows OUC's existing programs and proposed programs. The measures that were selected for inclusion in OUC's proposed programs were "bundled" into the re-named programs shown in this exhibit. For example, a number of technical equipment measures, including ceiling insulation, duct repair, efficient heat pumps, efficient water heaters, and other equipment-specific measures that were previously offered through specific named programs were bundled into a proposed Existing Home Program for applications in existing housing and into a New Home Program for applications in new residential construction.

Q. Please describe and provide some examples of the measure-specific and program-specific factors that OUC considered in developing its final OUC Portfolio of proposed programs and OUC's associated FEECA Goals.

A. Measure-specific and program-specific factors included OUC-specific program costs (instead of RI's "typical" program costs, which are more applicable to larger utility systems), OUC-specific participation rates for some programs, excluding some measures that do not make good economic sense for OUC, and including some measures with which OUC has had good success even though they may not have a benefit-cost ratio greater than 1.0.

Q. Are OUC's proposed goals based on an adequate assessment of the full Technical Potential of all available demand-side and supply-side

conservation and efficiency measures, including demand-side renewable energy systems, pursuant to Section 366.82(3), F.S.?

A. Yes.

Q. Do OUC's proposed goals adequately reflect the costs and benefits to customers participating in the measure, pursuant to Section 366.82(3)(a), F.S.?

A. Yes. RI's Participant Test analyses adequately and reasonably reflect the costs and benefits to customers who might participate in the DSM measures and programs studied.

Q. Do OUC's proposed goals adequately reflect the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions, pursuant to Section 366.82(3)(b), F.S.?

A. Yes. RI's Participant Test and Rate Impact Test analyses adequately and reasonably reflect the costs and benefits to the general body of ratepayers as a whole, including consideration of utility incentives and participant contributions.

Q. Do OUC's proposed goals adequately reflect the need for incentives to promote both customer-owned and utility-owned energy efficiency and

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demand-side renewable energy systems, pursuant to Section 366.82(3)(c), F.S.?

A. Yes. RI's analyses are based on reasonable and thorough analyses of incentives at different levels for the potential DSM measures studied.

Q. Do OUC's proposed goals or programs include any Demand Response measures or programs?

A. No. As noted above, RI's analyses identified a group of four potential Demand Response measures that could be implemented for large-demand (greater than 500 kW) commercial and industrial customers and that could pass the RIM and TRC tests. However, as I explained above, OUC is not proposing a program or goal based on these potential offerings because their benefits are mutually exclusive – a customer could only participate in one such program – while their significant startup costs are additive. OUC will consider and discuss offering such a program with our large customers and also with other utilities that already have such tariff offerings, with a view toward possibly implementing such a program that is mutually beneficial to participating customers and to OUC's general body of customers as a whole.

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C. Addressing the Needs of Low-Income and Rental Customers

Q. Please describe OUC's efforts to provide meaningful energy conservation opportunities and benefits to customers who live in rental properties.

A. OUC is committed to addressing the needs of all of our customers, including those who live in rental properties, which also includes significant numbers of customers in lower- and middle-income demographic categories. We target low-income and rental customers in two ways, through our Residential Efficiency Delivered Program and also through working with owners of existing multi-family residential projects to identify opportunities where we can implement or install a large number of measures, such as upgraded heat pumps and water heaters, duct repairs, and other energy-saving measures at multiple units at a single location.

All of OUC's residential customers are directly eligible for our Residential Efficiency Delivered Program, which is available to residential customers (single family home, townhome, or condominium) and provides up to $2,500 of energy and water efficiency upgrades based on the needs of the customer's home and the customer's income level. A Conservation Specialist from OUC performs a survey at the home and determines which home improvements have the potential of saving the customer the most money. The program is an income based program which is the basis for how much OUC will help contribute toward the cost of improvements and consists of three household income tiers:

> $40,000 or less, OUC will contribute 85 percent of the total cost (not to exceed $2,125);
>
> $40,001 to $60,000, OUC will contribute 50 percent of the total cost (not to exceed $1,250); and
>
> greater than $60,000 OUC will contribute the rebate incentives that apply toward the total cost.

To participate in the Efficiency Delivered Program, a customer must request and complete a free Residential Energy Survey. An OUC Conservation Specialist performs a survey at the home and determines which home improvements have the potential of saving the customer the most money. Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs based on a negotiated and contracted rate. The remaining portion of the cost the customer is responsible for can be paid directly to OUC or paid interest-free over a 24-month period on the participant's monthly electric bill.

OUC also targets owners and potential developers of multi-family rental housing for opportunities to reach a large number of rental customers at a single location. For example, at Canopy Apartments, a 296-unit complex, OUC provided rebates for AC heat pumps, heat pump water

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heaters, insulation, and duct repair through our custom commercial program. It is OUC's intention to seek out other apartment complexes, developers, and owners to work with to provide similar large scale energy efficiency deployments.

D. **Impacts of Building Codes and Appliance Efficiency Standards**

Q. Please discuss how OUC's current and potential future DSM programs are affected by building code requirements, e.g., the Florida Building Code, as it relates to energy efficiency requirements for residential and other buildings, and by appliance efficiency standards imposed by the federal government or the State of Florida.

A. In general, more stringent building code requirements result in more efficient buildings, thereby reducing the potential for cost-effective DSM programs as there is less opportunity to incentivize or achieve demand and energy reductions. In the same way, increased appliance efficiency standards reduce the potential for cost-effective DSM programs because as federal appliance standards increase and appliances become more efficient, there is less opportunity to incentivize or achieve demand and energy reductions. For example, if air conditioners were subjected to more stringent efficiency standards, e.g., a seasonal energy efficiency ratio ("SEER") of 15.0, then no utility would be able to justify a DSM program that provided a rebate for any unit with a SEER below 15.0, even though the utility might previously have been offering rebates for units with a SEER of 14.0.

Q. Please discuss how OUC's potential future DSM programs and measures have been affected by changes in appliance efficiency standards and Florida Building Code Requirements since 2019.

A. As explained in the testimony of Mr. Herndon, three changes affected the Technical Potential analyses in this case. First, the baseline efficiency ratings for residential central air conditioners and heat pumps were updated based on current U.S. Department of Energy conservation standards. Second, the baseline efficiency ratings for residential room air conditioners were updated based on U.S. Department of Energy conservation standards. Third, two-speed pool pump and variable speed pool pump measures were eliminated based on current Florida Building Code and U.S. Department of Energy conservation standards.

E. Consideration of Potential Greenhouse Gas Compliance Costs

Q. Do OUC's proposed goals adequately reflect the costs that may be imposed by state and federal regulations on the emission of greenhouse gases ("GHG"), pursuant to Section 366.82(3)(d), F.S.?

A. Yes. If anything, OUC's proposed goals are based on consideration of future carbon compliance cost assumptions that would support more energy conservation. There are no costs currently imposed on OUC or other Florida utilities by any state or federal carbon dioxide or GHG emissions regulations, and there is no state or federal requirement currently in place that establishes any such compliance costs with a known implementation date or magnitude. Recognizing and respecting the Orlando community's concerns, as well as national and global concerns, regarding climate change and the potential imposition of such GHG regulations, OUC engaged RI to perform a sensitivity case encompassing RIM, TRC, and Participant Test analyses based on reasonable – and possibly conservatively high – estimates of the future energy cost impacts of state and federal regulations applicable to GHG emissions. The assumptions used in this sensitivity analysis are somewhat aggressive, particularly given that there are presently no federal or state carbon regulation mandates applicable to OUC in effect or approved for future implementation.

Further, OUC's commitment to net zero greenhouse gas emissions by 2050 ensures that OUC and our customers will contribute meaningfully to reducing emissions.

V. DEMAND-SIDE RENEWABLE ENERGY EFFORTS

Q. Please describe OUC's existing demand-side renewable energy programs and efforts.

A. OUC continues to work actively to provide opportunities for its customers to participate in solar projects and programs. These initiatives include the Solar Photovoltaic (PV) Program, a Community Solar Program (OUCommunity Solar), and the Solar Thermal Program. Customers who participate in the Solar PV Program receive the benefit of net metering, which provides the customers with a monthly credit on their utility bills for energy produced in excess of what the home or business can use. Any excess electricity generated and delivered by the solar PV systems back to OUC's electric grid is credited at the customer's full retail electric rate. Residential and business customers who take part in the OUCommunity Solar Program have access to sustainable, maintenance-free solar energy without the hassles and costs associated with installing panels on their homes or businesses. Residential customers participating in the Solar Thermal Program currently receive a rebate of $900 for installing a solar hot water system. (Due to low participation in the Solar Thermal program, OUC plans to discontinue this program in 2025.) Federal incentives, such as the investment tax credit, are available to eligible customers to help minimize costs of solar PV and solar thermal systems.

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In addition to the solar projects owned and operated by OUC and our purchases of solar capacity and energy through power purchase agreements, OUC has experienced substantial adoption of solar PV and thermal systems by our customers. OUC currently has 9,306 PV and 584 solar thermal customers participating in these programs. This represents 103.74 MW of PV capacity and 1.228 MW of solar thermal capacity.

Q. Is OUC proposing any Demand-Side Renewable Energy goals or programs in the current Goals Dockets?

A. No. OUC has experienced excellent adoption of renewable energy measures, especially solar photovoltaic generating equipment, by OUC's customers without having to provide any incentives other than those embedded in our Net Metering tariff provisions. The relevant facts are that OUC has in place and will continue to provide significant opportunities for its customers to participate in solar projects and programs that are outside the scope of numeric FEECA Goals, and OUC also has in place and will continue to expand its extensive supply-side solar power initiatives.

Accordingly, OUC believes that no specific program offerings to promote demand-side renewable energy in OUC's service area are necessary.

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VI. OUC'S SUPPLY-SIDE ENERGY CONSERVATION AND EFFICIENCY EFFORTS

Q. How does OUC assess the Technical Potential for supply-side energy conservation, efficiency, and renewable energy opportunities?

A. OUC continually monitors the efficiency of its generation, transmission, and distribution systems, including both equipment and operations, and studies potential improvements in all three functions that show promise for cost-effectively improving the overall energy efficiency and cost-effectiveness of delivering power to OUC's customers.

Q. Please describe any supply-side energy conservation and efficiency measures or programs implemented by OUC.

A. In addition to the residential and commercial programs previously discussed, OUC continues to achieve significant energy savings reductions through supply-side initiatives, including the following programs and projects.

OUC's Conservation Voltage Reduction (CVR) Project is made possible by OUC's investment in its Advanced Meter Infrastructure (AMI) and more sophisticated distribution equipment. The availability of AMI customer load and voltage interval data provides an opportunity to optimize voltage control and thereby reduce energy consumption based on better awareness and monitoring of system conditions at customer service points.

Benefits of CVR include conservation related reductions in customer energy usage and line losses (with associated reductions in fuel usage) and lower demands on generation resources. As of December 2023, OUC had 157 feeders of the total of 190 feeders under CVR control and savings of approximately 28,815,000 kWh annually.

OUC continues to make investments in improving the operational energy efficiency at its generation facilities. The energy reduction realized in 2023 through these efficiency improvements totaled approximately 262,022,000 kWh.

OUC's OUCooling Chilled Water District program currently serves more than 200 customers and to whom OUC provides more than 61,000 tons of cooling. OUCooling's success relies on the fact that OUCooling can deliver cooling more efficiently and cost-effectively than our customers' alternative cooling costs. OUCooling succeeds by investing in higher efficiency chillers and equipment and optimizes its operations on a continuous basis. The enhanced efficient operation of OUCooling is estimated to have saved approximately 32,414,000 kWh in 2023.

Q. How are these supply-side efficiency and conservation measures reflected or incorporated into OUC's planning processes?

A. OUC's planning processes utilize the most current data and information available from our operations in our planning processes. Thus, whenever a supply-side efficiency improvement or energy conservation measure is implemented, the efficiency gains of that program start showing up in the data that are used in succeeding planning cycles and analyses.

Q. How does the presence and implementation of these supply-side conservation and efficiency measures affect potential savings from demand-side energy conservation programs?

A. Any improvement in the efficiency of our power supply and energy delivery systems naturally and inherently reduces the amount and value of savings available from reducing peak demand or incremental energy use on OUC's system. For example, an improvement in power production efficiency, e.g., a lower heat rate at a generator, reduces the amount of fuel required to deliver any given amount of power to customers, which results in less avoided-cost value from any conservation measure. Similarly, any reduction in energy output, which might include lower heat rates in production or improved transformation efficiency (lower line losses) on the transmission and distribution systems, needed to deliver service will result in a reduction in our marginal energy costs to serve, which correspondingly reduces the value of avoiding any energy that might otherwise be demanded by customers.

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Q. Is OUC proposing that the PSC set any goals for supply-side conservation and efficiency measures for OUC in this proceeding?

A. No. OUC naturally recognizes the potential benefits of supply-side energy conservation measures as well as the requirements and policies set forth in FEECA, and OUC's power supply teams continually monitor system operations and seek and implement measures to ensure the most efficient delivery of electric service to our customers. Section 366.82(2), F.S., encourages energy "efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base." Section 366.82(3), F.S., requires the PSC to evaluate the potential of "supply-side conservation and efficiency measures" in developing goals. OUC believes that any supply-side conservation and efficiency goals for OUC are unnecessary and potentially counter-productive. OUC continuously monitors the energy efficiency of all aspects of its supply-side functions, i.e., generation, transmission, and distribution, and implements cost-effective modifications and improvements as appropriate.

VII. SUPPLY-SIDE RENEWABLE ENERGY MEASURES

Q. Please describe OUC's existing supply-side renewable energy programs, investments, and initiatives.

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A. OUC is committed to making solar affordable and accessible for all customers. OUC has two large community solar farms, bringing the opportunity to use solar power to a variety of customers without paying for costly equipment and installation. OUC has found additional creative ways to use the sun's power — adding a floating solar array at our Gardenia facility and installing several solar sculptures around town.

In the near future, OUC will more than double its solar generation portfolio by purchasing power from two, 74.5-megawatt solar farms now under construction. OUC will also serve as the largest tenant of a new, 223.5-megawatt solar farm, purchasing 108.5 megawatts. In partnership with the Florida Municipal Power Agency, this will be one of the largest municipal-backed solar farms in the nation.

The most recent addition to OUC's owned solar generation portfolio is the Kenneth P. Ksionek Community Solar Farm at the Stanton Energy Center (SEC). This new array is unique in that it is one of the first solar farms in the country that sits atop a closed byproduct landfill at a power plant. This new facility will more than double OUC's community solar capacity, which gives OUC's residential and business customers access to sustainable, maintenance-free solar energy without the hassles and costs associated with installing panels on their homes or businesses.

VIII. CUSTOMER BILL IMPACTS

Q. What are the estimated impacts on a typical residential customer's bill if OUC were to implement OUC's proposed FEECA Goals, as well as the estimated rate impacts of goals based on the programs in the RIM Scenario and the TRC Scenario, respectively, for each year from 2025 through 2034?

A. The estimated impacts on a typical Residential customer bill of 1,000 kWh per month, of OUC's proposed FEECA Goals and the goals that would result from the RIM Scenario and TRC Scenario of DSM programs are presented in my Exhibit No. ____ [KMN-5]. In summary, the bill impacts if the programs that would meet OUC's FEECA Goals would begin at $0.45 per 1,000 kWh of Residential electric service in 2025 and increase to a cumulative impact of $0.59 per 1,000 kWh in 2034. The impact of goals based on the TRC Scenario, including the least expensive of the Demand Response programs that pass the TRC Test, would begin at $0.83 per 1,000 kWh of Residential service in 2025 and increase to $1.15 per 1,000 kWh in 2034. The impact of implementing only the Guaranteed Load Drop program, which is the least expensive of the four Demand Response programs that pass the RIM Test, would begin at $0.32 per 1,000 kWh of Residential service in 2025 and increase to $0.44 per 1,000 kWh in 2034.

C16-4705

(For clarity, as explained above, OUC does not plan to propose a goal or to implement a DR program at this time.)

IX. CONCLUSIONS

Q. Please summarize the main conclusions of your testimony.

A. OUC has a proven track record of implementing effective and successful DSM programs and both demand-side and supply-side solar power initiatives. OUC is in the best position to implement DSM, EE, and renewable energy measures that will best meet the needs of OUC's customers, the Orlando community, and the State as a whole. Even though none of OUC's proposed programs to meet its FEECA Goals pass the RIM Test, OUC's proposed FEECA Goals and programs include virtually all of OUC's existing DSM program measures, many of which pass the TRC Test, and OUC's FEECA Goals will result in meaningful peak demand reductions and energy savings. OUC's proposed FEECA Goals and programs are in the public interest.

OUC's record of developing and implementing significant amounts of both demand-side solar initiatives and supply-side solar power resources is widely recognized and respected. Taken together, OUC's proposed FEECA Goals and programs and OUC's net zero commitment will greatly increase the efficiency of electricity generation and use and will virtually eliminate the use of expensive fossil fuel resources in meeting the needs of OUC's customers and the Orlando community as a whole.

The PSC should approve OUC's proposed FEECA Goals and ultimately, the programs that OUC will implement to meet those Goals, because they serve the best interests of the Orlando community, OUC's customers, and Florida as a whole.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C16-4707

(Whereupon, prefiled direct testimony of Jeff Pollock was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals (Duke Energy Florida, LLC)	DOCKET NO. 20240013-EG Filed: June 5, 2024

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals (Duke Energy Florida, LLC)	**DOCKET NO. 20240013-EG** **Filed: June 5, 2024**

Table of Contents

LIST OF EXHIBITS

Exhibit	Description
JP-1	Trends in Generation Capital Costs
JP-2	Installed Cost of Generation Capacity Additions Since 2012
JP-3	CS & IS Monthly Incentive Reflecting Avoided Capital Costs

GLOSSARY OF ACRONYMS

Term	Definition
CCGT	Combined-Cycle Gas Turbine
CONE	Cost of New Entry
CS	Curtailable General Service
CT	Combustion Turbine
DEF or Company	Duke Energy Florida, LLC
DSM	Demand Side Management
EIA	Energy Information Administration
FIPUG	Florida Industrial Power Users Group
IS	Interruptible General Service
kW	Kilowatt
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt(s)
UFR	Under-Frequency Relay

C17-4751

DIRECT TESTIMONY OF JEFFRY POLLOCK

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 14323 South Outer Forty Road, Suite 206N, St. Louis, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science in electrical engineering and a Master of Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and in several Canadian provinces. This includes frequent appearances in rate cases and other regulatory proceedings before this Commission. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Duke Energy Florida, LLC (DEF). They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and substantial interest in the outcome of this proceeding.

Q WHAT ISSUES DO YOU ADDRESS?

A I am addressing DEF's proposed cost-effectiveness analyses for the Curtailable General Service (CS) and Interruptible General Service (IS) programs.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-3.**

Q ARE YOU ACCEPTING DEF'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. One should not interpret the fact that I do not address every issue raised by DEF as support of its proposals.

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A Although this proceeding is not a rate case, DEF is using this proceeding to reduce the CS and IS Demand Credits by 25% and 40%, respectively. As discussed later, the proposed reductions are based on a false premise that the CS and IS programs will not defer any capacity until 2029. The proposed reductions ignore the fact that the existence of these programs is long-standing and have resulted in DEF being able to avoid installing an additional 466 megawatts (MW) of generation capacity. Valuing the CS and IS programs at the avoided cost of combustion turbine (CT) peaking capacity would justify Demand Credits of at least $9.00.

Q WHAT IS THE CURTAILABLE SERVICE PROGRAM?

A The CS program is a series of rate schedules under which customers agree to curtail load at DEF's direction. The curtailment conditions in the CS tariffs are as follows:

> Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power

> customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only.[1]

Q WHAT IS THE INTERRUPTIBLE SERVICE PROGRAM?

A The IS program is a series of rate schedules under which customers agree to allow DEF to curtail the customer's load at DEF's direction. The curtailment conditions in the CS tariffs are as follows:

> Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only.[2]

Q ARE THERE ANY OTHER REQUIREMENTS UNDER THE INTERRUPTIBLE SERVICE PROGRAM?

A Yes. As previously stated, DEF has the ability to curtail an IS customer's load. This is because DEF requires an IS customer to have under-frequency relays (UFRs). UFRs can be triggered by DEF to immediately curtail an IS customer's load. This is in stark contrast to Curtailable Service, in which the customer is responsible for curtailing load.

[1] Duke Energy Tariff, Rate Schedule CS-2, Curtailable General Service, Twenty-Ninth Revised Sheet No. 6.235. The same provisions are also applicable to the other Curtailable Rate Schedules – CS-3, CST-2, and CST-3.

[2] *Id.*, Rate Schedule IS-2, Interruptible General Service, Thirtieth Revised Sheet No. 6.255. The same provisions are also applicable to Rate Schedule IST-2.

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Q DOES ALLOWING DEF TO CURTAIL AN INTERRUPTIBLE CUSTOMER'S LOAD PROVIDE ADDITIONAL VALUE?

A Yes. UFRs provide a faster response to curtailments. When DEF triggers an UFR, the customer's load is immediately removed from the system. By contrast, self-curtailment may not occur instantly, though customers will respond as necessary to avoid a significant compliance penalty.

Q WHAT ARE THE BENEFITS OF THE CURTAILABLE AND INTERRUPTIBLE PROGRAMS?

A CS and IS customers may be physically curtailed due to a capacity shortage or emergency anywhere in Peninsular Florida. By allowing load to be curtailed when resources are needed to maintain system reliability (that is, when there are insufficient resources to meet customer demand), DEF can maintain service to customers on other rates that take firm service. For this reason, DEF removes both CS and IS loads in assessing resource adequacy. Thus, both the CS and IS programs provide participants a lower quality of service than firm power because each can be interrupted as described above.

Q ARE THERE ANY FACTORS UNIQUE TO DEF'S CURTAILABLE AND INTERRUPTIBLE PROGRAMS?

A As compared to similar non-firm service options offered in other states, the CS and IS programs offer unparalleled flexibility to DEF and other Florida utilities. There are no limitations on the frequency and duration of curtailments, and curtailments may occur at any time during the year. Further, CS and IS curtailments may occur at times when there is a capacity shortage anywhere in the state of Florida. Thus, CS and IS loads

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are available 24x7 for deployment if needed by DEF, or by other Florida utilities, to maintain service to firm (retail and wholesale) customers.

Q HOW ARE CS AND IS CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE DEF?

A CS and IS customers pay for electricity under the rates, terms, and conditions of the Commission-approved rate schedules, which include both base rate charges and other charges under the various Commission-approved cost-recovery mechanisms. In exchange for an agreement to curtail load, CS and IS customers receive Demand Credits. Currently, the CS and IS Demand Credits are $7.72 per kilowatt (kW) of On-Peak Demand.

Q YOU PREVIOUSLY DESCRIBED HOW DEF PROVIDES NON-FIRM SERVICE UNDER RATES CS AND IS. APPROXIMATELY HOW MUCH NON-FIRM LOAD IS SERVED UNDER THESE TARIFF OPTIONS?

A The service provided under the CS and IS tariff options account for approximately 402 MW and 388 MW of load in the summer and winter months, respectively.[3]

Q ARE THE CURTAILABLE AND INTERRUPTIBLE SERVICE RATES THE ONLY NON-FIRM RATE OPTIONS OFFERED BY DEF?

A No. DEF provides approximately 2,630 MW and 1,960 MW of non-firm load in the winter and summer months, respectively.[4] Thus, there are other load management programs besides CS and IS. This includes Load Management, Conservation, and Other Demand Reductions – which are either dispatchable or non-dispatchable.

[3] DEF 2024 Ten-Year Site Plan at 2-15 and 2-18 (Apr. 2024).

[4] *Id.*

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Q DOES DEF INCLUDE NON-FIRM LOAD IN ASSESSING RESOURCE ADEQUACY?

A No, as previously explained, DEF removes the CS and IS load when assessing adequacy. As stated in its 2024 Ten-Year Site Plan:

> ***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.[5] (emphasis added)

Hence, non-firm (*i.e.,* Interruptible, Load Management, Conservation, and Other Demand Reductions) loads are removed in determining the net firm demand that DEF is obligated to serve.

Q DOES THE FACT THAT CURTAILMENTS OF NON-FIRM LOAD HAVE BEEN INFREQUENT LESSEN THE VALUE OF THIS LOAD TO DEF'S FIRM CUSTOMERS?

A No. Non-firm load is no different than a generating unit that is held in reserve until the capacity is deployed to meet system demand or respond to outages of either generation or transmission.

[5] *Id.* at 3-46.

C17-4757

Q WILL NON-FIRM LOAD BE MORE BENEFICIAL IN THE FUTURE THAN IN THE PAST?

A Yes. As DEF has chosen to increasingly rely on weather-sensitive, intermittent solar generation, the ability to call on non-firm load will increase in value.

Q HOW IS DEF PROPOSING TO CHANGE THE DEMAND CREDITS?

A DEF is proposing to reduce the CS Demand Credit from $7.72 to $5.82 per kW, a 25% reduction. The IS Demand Credit would be reduced from $7.72 to $4.62 per kW, a 40% reduction.

Q WHY IS DEF PROPOSING TO REDUCE THE CS AND IS DEMAND CREDITS BY 25% AND 40%, RESPECTIVELY?

A DEF provided no explanation or documentation to support the proposed decrease to $5.82 and $4.62 per kW for CS and IS Demand Credits, respectively. Based on a review of DEF's Application, it would appear that the proposed 25% and 40% reductions are somehow derived from updated cost-effectiveness tests. My understanding is that cost-effectiveness tests measure the benefits provided by the CS and IS programs based on the cost of avoided generation capacity relative to the costs of the programs, which are comprised primarily of the CS and IS Demand Credits that DEF is proposing to reduce in this (non-rate case) proceeding.

Q HAS DEF PROVIDED THE NECESSARY DOCUMENTATION SUPPORTING THE SIGNIFICANT REDUCTIONS IN THE CS AND IS DEMAND CREDITS?

A No. When asked to supply detailed workpapers, DEF produced non-functional EXCEL workbooks, mostly comprised of values (rather than formulas that reveal how the calculations were made) without supporting documentation. The paucity of evidence supplied by DEF is revealed by the fact that the significant reductions DEF is proposing

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in the CS and IS Demand Credits are described in a single sentence on page 22 of the Direct Testimony of Tim Duff. Further, DEF provided no discussion of the proposed changes in its pending rate case, and it declined to provide supporting documents, including quantifying the bill impacts on CS and IS customers.

Q HOW WOULD 25% AND 40% REDUCTIONS IN THE CS AND IS DEMAND CREDITS IMPACT BASE RATES CHARGED TO THESE CUSTOMERS?

A The proposed reductions would generate additional revenue of $21.1 million from CS and IS customers. Further, DEF has ignored the $21.1 million increase due to the lower Demand Credits in the pending rate case and, therefore, this increase would be in addition to the $22.9 million (30%) base revenue increases that DEF is proposing to implement in 2025. Not only would the combined rate increases violate the principals of gradualism, they would have a deleterious impact on the cost competitiveness and sustainability of the affected customers.

Q HAVE YOU REVIEWED DEF'S COST-EFFECTIVENESS TESTS FOR THE CURTAILABLE AND INTERRUPTIBLE PROGRAMS?

A Yes. DEF's cost-effectiveness tests appear to assume that the existing CS and IS programs provide zero benefits to customers until 2029. Further, the benefits that DEF attributes to the CS and IS programs for the years 2029 and beyond are based on the assumed cost of a CT peaking unit on an existing (*i.e.,* "Brownfield") DEF plant site. According to DEF, the installed capital cost of a 2029 CT would be $735 per kW in 2023 dollars.[6] However, because DEF wrongly assumes a negative Generator Cost Escalation Rate (-1.09%) from 2023 to 2032, the actual installed capital cost in 2029

[6] Direct Testimony of Tim Duff, Exhibit TD-4.

would be lower.[7] It is unlikely that inflation would remain negative for eight years for the vast majority of goods and services, and inflation is one of the reasons that DEF is seeking to increase rates. Therefore, it is inappropriate for DEF to assume a negative Generator Cost Escalation Rate.

Q ARE DEF'S COST-EFFECTIVENESS ANALYSES OF THE CS AND IS PROGRAMS VALID?

A No. First, DEF's analyses misconstrue the role of cost-effectiveness tests in setting rates. Further, as discussed later, both the concept of and assumptions used in DEF's cost-effectiveness tests are flawed.

Q HOW ARE DEF'S COST-EFFECTIVENESS TESTS CONCEPTUALLY FLAWED?

A Determining the reasonableness of a rate should not be conflated with the determination of whether a particular demand side management (DSM) or load management program is cost-effective and should be offered or expanded. The former is a ratemaking issue, while the latter is a resource planning issue. DEF's comparison of apples and oranges misses the mark.

Q HOW IS RESOURCE PLANNING DIFFERENT FROM RATEMAKING?

A Resource planning is, by definition, forward looking; whereas ratemaking reflects known past decisions and costs that have mostly been incurred in the past, as well as the projected additional costs for the test year.

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[7] *Id.*

Specifically, resource planning identifies the range of options that can allow a utility to meet its future needs at the lowest reasonable cost. In the context of non-firm service, resource planning can help determine if in the future it is cost-effective to implement, expand, or close a particular option to new business. Importantly, resource planning does not determine what the rates should be for those resources. The determination of rates for those resources is more appropriately handled in a base rate case.

Ratemaking addresses the recovery of costs associated with the utility's existing resources, which include both supply side and demand-side resources, after the Commission has determined that the resource is both prudent and reasonable. The costs of those resources are known and recoverable in rates. Importantly, the costs eligible for recovery in rates are not adjusted, even if the resource is no longer cost-effective. For example, if an existing combined-cycle gas turbine (CCGT) is no longer cost-effective because it can no longer compete with other resource options, the utility is still allowed to recover those costs in rates because the Commission has deemed them to be prudent and reasonable.

Similarly, when used in the context of evaluating non-firm service, the reasonableness of any non-firm rate can be assessed by determining whether the utility has actually avoided constructing new capacity and quantifying the costs associated with this avoided capacity. If the Commission determines that a non-firm rate option is no longer providing benefits to the general body of ratepayers, it can require the utility to close the rate to new business.

Q DO THE COMMISSION'S RULES ADDRESS COST-EFFECTIVENESS TESTS IN GENERAL?

A Yes. Cost-effectiveness is addressed in the Commission's Rule on Non-Firm Electric Service.[8] Specifically:

> Purpose. The purposes of this rule are: to define the character of non-firm electric service and various types thereof; to require a procedure for determining a utility's maximum level of non-firm load; and to establish other minimum terms and conditions for the provision of non-firm electric service.

Q HOW IS COST-EFFECTIVENESS DEFINED?

A Cost-effectiveness is defined as follows:

> (c) "Cost effective" in the context of non-firm service shall be based on avoided costs. It shall be defined as the net economic deferral or avoidance of additional production plant construction by the utility or in other measurable economic benefits in excess of all relevant costs accruing to the utility's general body of ratepayers.[9]

Q HOW ARE COST-EFFECTIVENESS TESTS USED?

A Cost-effectiveness tests are used in the conservation goals dockets to determine the maximum level of non-firm load; specifically, whether a new DSM or load management program should be implemented and/or whether an existing program should either be expanded or closed to new business. Importantly, cost-effectiveness tests should not be used to set rates because they cannot measure the benefits of the capacity that has been avoided by the presence of the CS and IS programs.

[8] Fla. Admin. Code Rule 25-6.0438(2).

[9] Fla. Admin. Code Rule 25-6-0438(3)(c).

Q HOW ARE DEF'S COST-EFFECTIVENESS TEST ASSUMPTIONS FLAWED?

A As previously stated, DEF is assuming that CT capital costs will be 1.09% per year lower in 2029 as compared to the 2023 (base year) cost. However, there is no evidence of declining CT capital costs. The evidence clearly demonstrates that CT capital costs are increasing, not decreasing.

For example, **Exhibit JP-1** shows trends in the installed costs of CT generating units as compiled in two publicly available sources: (1) the Energy Information Administration's (EIA's) Annual Energy Outlook reports (the orange bars) and (2) the cost-of-new entry (CONE) prices published by MISO in its annual Planning Resource Auctions (the blue bars). The CONE prices shown reflect the increased cost to construct a new CT in MISO local resource Zone 9, which includes Louisiana, Mississippi and Texas (along the Gulf Coast). As can be seen, the projected installed costs of a CT (as measured by the EIA and MISO) have recently trended upward.

Thus, there is no discernable decline as indicated in Mr. Duff's avoided unit assumptions.

Q HAVE DEF'S GENERATION CAPITAL COSTS DECLINED?

A No. This is shown in **Exhibit JP-2**, which is a history of DEF's capacity additions from 2004 through 2023. With the exception of Bartow, the installed cost per kW of capacity additions over the past 20 years has increased. This historical trend invalidates DEF's new cost-effectiveness analyses, which assume a negative Generator Cost Escalation Rate from 2023 to 2032.

Q DOES DEF'S PROPOSAL TO REDUCE THE CS AND IS DEMAND CREDITS BY 25% AND 40%, RESPECTIVELY, RAISE ANY OTHER CONCERNS?

A Yes. Very large reductions in the Demand Credits could have adverse consequences. For example, changes such as these could motivate customers to reduce or shut down their operations. Another unintended consequence could be that customers switch from non-firm to firm service. Any such adverse reaction could adversely impact DEFs' future generation plans and its remaining customers.

Q IS THERE ANY REASON TO BELIEVE THAT CUSTOMERS WOULD CONTINUE THEIR PARTICIPATION IN THE CS AND IS PROGRAMS IF THE DEMAND CREDITS ARE REDUCED BY 25% AND 40%, RESPECTIVELY?

A No. Non-firm service is not cost-free or risk-free. As previously stated, curtailments can occur at any time when capacity is insufficient throughout Peninsular Florida, not just in DEF's service territory. Thus, IS and CS participants take on risk and have to incur costs to be able to safely curtail load when notified.

For example, IS customers had to invest in UFRs that allow DEF to immediately curtail their entire load as a prerequisite to qualifying for non-firm service under the IS rate schedule. This is in addition to any behind-the-meter investments and protocols that allow the customer to safely shut down production and mining processes.

Reducing the incentive payments as DEF is proposing could substantially change customers' assessments of the risks and benefits of the programs. If the participants believe that the benefits of remaining on non-firm service will be substantially reduced and are no longer justified by the risks, as DEF is proposing in this case, they may decide to either curtail or shut-down operations or, if it is more cost-effective, convert to firm service.

Q WHAT WOULD HAVE HAPPENED IF ALL CURTAILABLE AND INTERRUPTIBLE CUSTOMERS HAD CHOSEN FIRM SERVICE RATHER THAN NON-FIRM SERVICE?

A Keeping in mind that non-firm load is not considered at all in resource planning, DEF would have had to install 100% of this as additional capacity to serve the IS and CS loads plus another 20% reserve margin. So, 388 MW of CS and IS non-firm load in the winter months would require DEF to install an additional 466 MW of capacity.

If that additional 466 MW of capacity had been installed over the period 2004 through 2023, DEF would have incurred an average installed cost for this additional capacity of about $870 per kW ($712 per kW excluding solar capacity), as shown in **Exhibit JP-2**.

Using $712 per kW as the average installed cost of incremental capacity, the annual cost avoided by a transmission-level customer taking non-firm service was approximately $9.08 per kW per month. The $9.08 per kW per month avoided capacity cost is derived on page 1 of **Exhibit JP-3**. It is based on DEF's test-year carrying charges. This is significantly higher than the current $7.72 per kW Demand Credit.

Q THE $712 PER KW AVOIDED CAPITAL COST ASSUMES THAT DEF WOULD HAVE INSTALLED THE SAME MIX OF THERMAL GENERATION TO PROVIDE FIRM SERVICE TO CS AND IS CUSTOMERS. WHAT IF DEF HAD INSTALLED COMBUSTION TURBINES INSTEAD OF CCGTS?

A **Exhibit JP-3,** page 2 quantifies the avoided cost of non-firm capacity had DEF installed CTs during this period to firm-up the CS and IS loads. As can be seen, the corresponding annual revenue requirement avoided by a transmission-level customer taking non-firm service was $9.15 per kW per month. This amount is also significantly higher than the current $7.72 per kW CS and IS Demand Credits.

Q HAVE THE CS AND IS PROGRAMS PROVIDED (AND WILL CONTINUE TO PROVIDE) BENEFITS TO THE GENERAL BODY OF DEF CUSTOMERS?

A Yes. The capacity costs avoided by providing non-firm service under the CS and IS rate schedules exceed the incentive payments to these customers. Hence, from a ratemaking perspective, both the CS and IS programs are cost-effective.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject DEF's proposal to drastically reduce the CS and IS Demand Credits.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 14323 South Outer Forty Road, Suite 206-N, Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing

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requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

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APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Direct	TX	Transmission Operation and Maintenance Expense; Property Insurance Reserve; Class Cost-of-Service Study; Rate Design; Tariff Changes	5/16/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Cross-Rebuttal	TX	Turk Remand Refund	5/10/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Surrebuttal	SC	Class Cost-of-Service Study; Revenue Allocation and Rate Design	4/29/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Direct	TX	Turk Remand Refund	4/17/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/8/2024
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	55378	Direct	GA	Deferred Accounting; Additional Sum; Specific Capacity Additions; Distributed Energy Resource and Demand Response Tariffs	2/15/2024
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals (Duke Energy Florida, LLC)	**DOCKET NO. 20240013-EG Filed: June 5, 2024**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 14323 South Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20240013-EG; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 5th day of June 2024.

KITTY TURNER
Notary Public, Notary Seal
State of Missouri
Lincoln County
Commission # 15390610
My Commission Expires 04-25-2027

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2027.

C17-4778

(Whereupon, prefiled direct testimony of MacKenzie Marcelin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals Florida Power & Light Company	))))	DOCKET NO. 20240012-EG
In re: Commission Review of Numeric Conservation Goals Duke Energy Florida, LLC	))))	DOCKET NO. 20240013-EG (Florida Rising and LULAC only)
In re: Commission Review of Numeric Conservation Goals Tampa Electric Company	))))	DOCKET NO. 20240014-EG (Florida Rising and LULAC only)
In re: Commission Review of Numeric Conservation Goals JEA	))))	DOCKET NO. 20240016-EG (Florida Rising only)
In re: Commission Review of Numeric Conservation Goals Orlando Utilities Commission	))))	DOCKET NO. 20240017-EG (Florida Rising only)

TESTIMONY OF MACKENZIE D. MARCELIN ON BEHALF OF FLORIDA RISING, LEAGUE OF UNITED LATIN AMERICAN CITIZENS, AND ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA

June 5, 2024

Q. Please state your name and business address.

A. My name is MacKenzie Marcelin. My business address is 10800 Biscayne Blvd Suite 1050, Miami, FL 33161.

Q. What is your current position?

A. I am the Climate Justice Director at Florida Rising.

Q. What are your duties as Climate Justice Director?

A. In my role I am responsible for developing campaign strategies that address the climate crisis from a racial justice lens at the local, state, and federal levels. I am also tasked with designing and implementing actions and events to mobilize base, allies, and partners toward key climate justice policy wins. Lastly, I develop and activate natural disaster response and manage disaster response initiative work.

Q. Please summarize your qualifications and work experience.

A. In 2019, I was hired as a climate justice organizer at Florida Rising where I began my organizing work in climate justice. My general qualifications include organizing for 6 years and organizing multiple energy justice campaigns. I have experienced electricity disconnections and know the hardships they can cause. I have personally experienced energy insecurity, and as a Floridian, have had to engage in preparation for multiple hurricanes. I have a Bachelor of Arts in History from the University of Florida, with a focus on the Black experience, race, and inequality. My litigation experience is limited, however, I have participated in a few dockets at the Florida Public Service Commission.

Q. Have you ever testified before the Florida Public Service Commission before?

A. Yes, I have participated in a few dockets at the Florida Public Service Commission advocating on behalf of Florida Rising's values of racial and economic justice and for Florida Rising's members, who are mostly black and brown, and are facing high energy burdens due to high electric bill costs. In Docket Nos. 20190015-EG, 20190016-EG, 20190018-EG, 20190020-EG, 20190021-EG, *In re: Commission review of numeric conservation goals*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2019/08186-2019/08186-2019.pdf. In Docket No. 20200219-EI, *In re: Petition to initiate emergency rulemaking to prevent electric utility shutoffs, by League of United Latin American Citizens, Zoraida Santana, and Jesse Moody*, I gave testimony to the importance of halting electric power disconnections for the health of members of low-income communities. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2020/11330-2020/11330-2020.pdf. In Docket No. 202000181-EU, *In re: Proposed amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a video of my remarks here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3368 and here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3335.

Q. Have you ever testified as a formal witness before the Florida Public Service Commission?

A. Yes, in the FPL Rate Case I submitted formal testimony on behalf of Florida Rising (Docket 20210015-EI). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2021/06451-2021/06451-2021.pdf. https://www.floridapsc.com/pscfiles/library/filings/2021/06451-2021/06451-2021.pdf.

Q. On whose behalf are you testifying in this proceeding?

A. Florida Rising, the League of United Latin American Citizens of Florida (also known as "LULAC"), and the Environmental Confederation of Southwest Florida (also known as "ECOSWF").

Q. What is Florida Rising?

A. We are a people-powered organization made up of members advancing economic and racial justice across Florida. We build independent political power that centers historically marginalized communities so everyday Floridians can shape the future. As an organization, we engaged in the 2019 FEECA Hearings, intervened in the 2021 FPL Rate Case, commented on the energy-efficiency rulemaking proceeding (Docket No. 20200181), including in the Rule hearing, commented in some of the fuel dockets and storm recovery dockets, and, in addition to this proceeding, have intervened in the Duke Energy Florida Rate Case and Tampa Electric Company Rate Case, happening at the same time as this case.

Q. Does Florida Rising have members in the utilities subject to this proceeding?

A. Yes, Florida Rising has members in Florida Power & Light Company's ("FPL"), Duke Energy Florida's ("Duke"), Tampa Electric Company's ("TECO"), JEA's, and Orlando Utility Commission's ("OUC") service

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territories. We have hundreds of members in Southeast Florida in FPL's territory, at least 53 active members in Duke's territory (Pinellas County, plus we have many more Duke members in the Orlando-area), at least 105 active members in TECO's territory (Hillsborough County), and 96 active members in JEA's territory (Duval County). We have a substantial number of Florida Rising members in OUC's territory, and I personally know several members who are OUC customers. Also, Florida Rising as an organization pays electric bills to FPL, Duke, and TECO for our offices located in those territories.

Q. Why is Florida Rising in this proceeding?

A. As mentioned before, Florida Rising is an organization made up of members focused on empowering marginalized communities to advance racial and economic justice across Florida. In our climate justice work we want a future where the frontline and most impacted communities are at the center of energy policy, disaster response, and all climate change initiatives.

Florida's dependency on fossil fuels has led to our current energy system polluting our communities, fueling our climate crisis, and leaving many in dire economic straits. These issues in our energy system have an unequal and harmful impact on Black, Brown, and low-income communities. A 2020 report by ACEEE found that low-income, Black, Hispanic, and Native American households face higher energy burdens than the average household.[i] Rising housing costs, insurance costs, and stagnant wages have made Florida unaffordable, leaving families with high energy burdens. haa The financial hardship is forcing people to make tough choices between keeping the lights on or paying for groceries or prescription medications or living in hot and unsafe housing conditions. All the while, major utility companies have been experiencing record profits over the last few years.

Florida has been experiencing an uptick in climate disasters like extreme heat, sea level rise, flooding, and severe storms, which are leaving our neighborhoods and infrastructure vulnerable. Record high heat days,[ii] stronger and more frequent storms,[iii] and other climate disasters are a direct result of our energy system's reliance on dirty fossil fuels. The increase in extreme heat days means that more energy and access to A/C are a requirement in Florida for keeping our homes healthy, habitable, and cool. Stronger and more frequent storms threaten the reliability of our electrical grid, causing loss of property to our state and an increase in illness and death. The increase in extreme disasters places an unfair burden on communities' colors and often leads them into a more vulnerable state than before.

Yet, Florida Rising believes that we must transition to a clean energy system with more community members included in the decision-making . If we do that, we can ensure that everyone has access to clean, affordable energy that creates jobs and is environmentally friendly and resilient against natural disasters.

Q. Have you looked at how Florida ranks nationally when it comes to residential electricity bills?

A. Yes, according to the most recent data from the Energy Information Administration ("EIA"), for 2023, Florida had the fourth highest electricity bills in the nation with an average monthly residential electricity bill of $167.76, behind only Hawaii, Connecticut, and New Hampshire. This data is attached to my testimony as Exhibit MM-1.

Q. How did you determine this?

A. I simply calculated the average monthly revenue per residential customer for each utility and state and combined the data together.

Q. Is this a standard-practice for comparing electric bills?

A. Yes, the Energy Information Administration calculates the average residential electric bills itself using this methodology and compares average monthly bills across utilities and states using this method every year. I have attached previous year data, as compiled by the Energy Information Administration, for 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021, and 2022, as Exhibits MM-2–MM-10.

Q. How has Florida's Average Monthly Residential Bills changed since 2014, the last time the energy efficiency goals were set?

A. They have significantly increased, as shown in the table below, both in absolute terms as a dollar amount, and relative to other States. Also, it should be known that the 2023 data for Florida only includes the investor-owned utilities and JEA, as the annual reporting data from the Energy Information Administration has not been released yet. JEA and the investor-owned utilities cover most Floridians, but it is possible that when the rest of the municipal and cooperative data is reported, the average monthly residential electric bill for Florida will drop slightly.

Year	Average Monthly Residential Electric Bill	State National Ranking
2014	$129.86	11
2015	$132.16	8
2016	$123.37	14
2017	$126.44	8
2018	$128.10	13
2019	$129.65	10
2020	$128.64	11
2021	$130.40	14
2022	$154.51	7
2023	$167.76	4

Q. What's the importance of showing other States?

A. Showing other States highlights that whatever factors are driving Florida's electric bills higher, such as higher fuel costs or hotter summers, are not impacting other States in the same way. All States are impacted by higher fuel costs and inflation, and all States are experiencing hotter summers.

Q. What's the significance of 2014?

A. That's the last time the Public Service Commission set energy-efficiency goals for the utilities. In that proceeding, the Commission set goals using the Rate Impact Measure ("RIM") test, under the theory that the RIM test would help keep rates low and thus keep bills down for Floridians.

Q. Do you believe that the energy-efficiency goals set in 2014 have been successful?

A. No. Bills have continued to rise at an extraordinary pace, especially over the last couple of years. Florida used to have electricity bills that were higher than other States but bounced around being about the tenth most expensive in the nation. Now, Florida has the fourth highest electricity bills in the nation. Unfortunately, with additional rate cases happening, it seems like Florida is on the path to becoming the most expensive State in the nation.

Q. Have rates at least stayed low?

A. No. The 2022 Energy Information Administration data shows that the effective rate, the amount residential consumers pay per kWh regardless of rate structure (dividing amount of revenue from the residential class by electricity sales (kWh)) places Florida now in the top-22 of States in the nation for electricity rates. Exhibit MM- 2.

Q. How about the utilities that are subject to this proceeding? How do their average residential electric bills compare?

A. Tampa Electric Company currently has some of the highest residential electricity bills in the entire nation. In the TECO Rate Case, TECO already admitted that the information it submits to the EIA is accurate and that its total billed revenue for the residential class divided for each month by the customer count for that month, averaged for all twelve months, results in $191.95. Although TECO denies the importance of this calculation, the calculation represents the average revenue per residential customer per month. In other words, it represents the average monthly residential electricity bill. TECO also admitted that, as presented by the EIA for 2023, of the 149 electric utilities with over 100,000 residential customers, TECO had the third highest average monthly residential electricity bills. These admissions are attached as Exhibit MM-11.

Duke Energy Florida is not far behind, with average residential electric bills in 2023 of $186.56, the fifth highest in the nation for utilities with more than 100,000 residential customers. FPL wasn't far behind that, with an average residential electric bill of $170.11, the eighth highest in the nation out of the 149 utilities reporting with more than 100,000 residential customers. JEA was a lot better with an average monthly residential electricity bill of $136.31, being 58 out of the 149 reporting utilities. In fact, if it wasn't for JEA bringing down the average, and if Florida's rank was measured with just the investor-owned utilities, Florida would have easily been the third most expensive state for residential electricity bills in the nation in 2023. All of these calculations are included in my electric bill comparisons from the EIA 2023 data and are attached as Exhibit MM-12.

Q. How about OUC?

A. OUC doesn't report using the EIA-861M data. It reports the annual data, so I have the 2022 bill data for OUC. It had an average electric residential bill of $138.55 in 2022, which is lower than the investor-owned utilities but still relatively high. The 2022 data is attached as Exhibit MM-13.

Q. How do Florida-utilities frequently do "bill" comparisons?

A. They frequently do "bill" comparisons using a standardized 1,000 kWh assumption.

Q. What's your opinion regarding that kind of comparison?

A. It is an arbitrary and misleading comparison. Consumers do not pay bills based off of 1,000 kWh of usage; they pay bills off of actual usage. Florida utilities often have higher rates above 1,000 kWh of usage, and most average above 1,000 kWh of usage. Most utilities out of state have consumers that use less than 1,000 kWh of usage. Thus, 1,000 kWh of usage frequently understates the actual bills Florida consumers pay, while overstating the actual bills others pay. Even in this proceeding, the utilities offer bill comparisons for energy-efficiency goal-setting purposes of 1,000 kWh of usage.

Q. Is there an issue with that?

A. Yes. Energy-efficiency saves electricity and lowers usage. Comparing "bills" with different amounts of energy-efficiency while still maintaining 1,000 kWh of usage will, of course, make more energy efficiency look more costly, as energy-efficiency measures are not free. Thus, the more energy efficiency a utility does, the more "expensive" it will look on a 1,000 kWh "bill" comparison, even though the opposite may be true for actual bills, i.e., what people actually pay.

Q. Do you have an opinion about Florida's energy efficiency historical performance?

A. Yes. The Florida electric utilities subject to FEECA have some of the worst energy efficiency performance in the nation. A common way of comparing actual performance on energy efficiency between utilities is to look at the total amount of energy each utility saved in a year as a percent of that utility's total retail sales for the same year. This gives a fair comparison of how each utility is doing, since in absolute numbers, a small utility with excellent energy efficiency achievements won't save as much total energy as a huge utility with abysmal performance.

In 2021, the latest year for which the analysis has been completed, the national average for energy savings as a percent of total retail sales was 0.68%. SACE Energy Efficiency in the Southeast Report (March 2023), attached as Exhibit MM-14, at 4. In that same year, the Florida average was just 0.08%, with the FEECA utilities ranging from 0.3% on the high end for OUC and

TECO, to a low end of 0.03% for FPL. *Id.* at 20. That made FPL's energy efficiency performance more than *twenty* times lower than the national average.

Using data reported by the FEECA utilities, I have calculated the energy efficiency performance of these utilities for 2023, summarized in the tables below. The data is taken from the utilities' 2023 Annual DSM Reports to the PSC, attached as Exhibits MM-15–MM-19 and from Schedule 2 of their 2023 Ten Year Site Plans, excerpted as Exhibits MM-20–MM-24. I have prepared a workpaper supporting these calculations and attached it as Exhibit MM-25.

2023 Annual System-Wide Energy Efficiency Savings Achieved			
Utility	Total GWh Savings at Meter	Total Retail Sales At Meter (GWh)	Total Energy Saved as Percent of Total Retail Sales
FPL	79.863	127,904	0.06%
DEF	57.955	40,832	0.14%
TECO	56.723	20,791	0.27%
JEA	7.861	12,295	0.06%
OUC	9.956	7,155	0.14%

2023 Annual Residential Energy Efficiency Savings Achieved			
Utility	Residential GWh Savings at Meter	Total Retail SalesAt Meter (GWh)	Residential Energy Saved as Percent of Total Retail Sales
FPL	32.328	127,904	0.03%
DEF	47.504	40,832	0.12%
TECO	28.03	20,791	0.14%
JEA	3.478	12,295	0.03%
OUC	1.786	7,155	0.02%

2023 Annual Commercial & Industrial Energy Efficiency Savings Achieved			
Utility	C&I GWh Savings at Meter	Total Retail Sales At Meter (GWh)	C&I Energy Saved as Percent of Total Retail Sales
FPL	47.5352	127,904	0.04%
DEF	9.50087	40,832	0.02%
TECO	28.6932	20,791	0.14%
JEA	4.38341	12,295	0.04%
OUC	8.17036	7,155	0.11%

The FEECA utilities continue to fall far behind the national average, with the result that customers in Florida use and pay for more electricity than they would otherwise need. Even the limited energy efficiency programs that are offered to customers have not been fairly distributed. The table below shows the breakdown of savings by class as a percentage of the total.

2023 Annual Class Shares of Total Achieved Energy Efficiency Savings		
Utility	Residential Share of Total Energy Savings (%)	C&I Share of Total Energy Savings (%)
FPL	40.48%	59.52%
DEF	81.97%	16.39%
TECO	49.42%	50.58%
JEA	44.24%	55.76%
OUC	17.94%	82.07%

Residential customers make up a majority of each of these utilities both by accounts and by total sales. Exhibits MM-20–MM-24. Yet for almost every utility, most energy efficiency savings go to the commercial and industrial classes. That means that residential customers pay more into the programs through the energy conservation cost recovery clause, but businesses get most of the benefits. OUC stands as the most lopsided, giving businesses more than 82% of total savings, and less than 18% to residential customers. As discussed later, most energy efficiency funding goes to bill credits for big commercial and industrial customers for participating in interruptible or curtailable programs – even though they don't actually get interrupted or curtailed.

Q. Have you reviewed the energy-efficiency goals proposed by the utilities in this proceeding?

A. Yes.

Q. What, if any, opinion do you have regarding the proposed goals?

A. I have utility-specific criticisms detailed below. However, I am glad to say at least none of the utilities proposed goals for zero, and all seem to recognize the importance of meeting the needs of low-income Floridians and renters. The utilities also seem to recognize that setting goals just based on the RIM test and the 2-year payback screen doesn't work for actual utility programs, especially for low-income customers, so I am glad that the utilities did not rigorously apply the RIM test and 2-year payback screen. So, in that regard, there's definitely been an improvement from the proposals five years ago during the 2019 proceeding. But overall, I would say that the utility proposals are still inadequate to meet the needs of Floridians, especially low-income customers. However, as I note later in in my testimony, there is variation amongst the utilities, with Duke having some of the better goal-proposals, and FPL having some of the worst, especially given its size (although I would note that FPL's proposal is still an improvement from what they have historically proposed, and so it's good to see that they are moving in the right direction).

Q. Do you have an opinion regarding the use of the 2-year payback screen as a means to screen for freeriders?

A. Yes.

Q. What is that opinion?

A. The 2-year payback screen is a crude instrument that doesn't reflect Floridians' lived-experiences. In my role as Climate Justice Director of Florida Rising, I interact with ordinary Floridians (as in, not connected to the energy-world outside of receiving a monthly electric bill) on an almost daily basis. I've yet to meet someone that knows what energy efficiency measures pay for themselves in two years or less and which ones take longer than two years to pay for themselves. Also, many of the people I interact with everyday struggle to pay their existing bills as it is. Most low-income customers that I know cannot afford to purchase energy-efficiency measures that pay for themselves in less than two years because they are struggling to pay their bills day-to-day. So the idea of making an upfront investment that pays for itself in less than two years is simply something many people cannot afford to do. Also I reject the phrasing and characterization of customers utilizing energy efficiency measures as "freeriders," because the cost of the energy efficiency measures are paid by the customers through the Energy Conservation Cost Recovery Clause. Not only that, but all the non-low-income energy efficiency programs require customers to pay money to access said programs.

Q. You've been involved with these kinds of proceedings for over five years now. Can you name the energy-efficiency measures that pay for themselves in less than two years without looking it up?

A. No. I can probably name a couple at this point, like faucet aerators and LED lightbulbs, but I certainly cannot name an exhaustive list.

Q. Have you examined FPL's proposed goals in this proceeding?

A. Yes.

Q. And what's your opinion regarding those goals?

A. FPL is the largest and wealthiest utility in the State, and serving most Floridians, it should set the example to other utilities for good energy efficiency goals. Yet, despite being several times the size of the next largest utility (Duke), FPL has proposed goals that, in absolute terms, are significantly lower than what Duke has proposed. That doesn't make sense, especially as it relates to low-income customers. TECO, a utility significantly smaller than FPL, proposes to reach almost as many low-income customers (7,500) to be served as FPL does. And, as I note later in my testimony, I think this should be expanded and significantly scaled up.

Q. What do you propose?

A. As it relates to FPL's low-income programs, I propose expanding them as reflected below to match TECO's proposals on a per-capita basis. FPL has over 6.92 times the number of residential customers as TECO, Exhibit MM-12, and therefore I propose that FPL try to reach 6.92 times as many low-income customers as Duke. This is reflected in the table below.

Proposed Increase to FPL Low-Income Program Participation			
Year	FPL Proposed Participation	TECO Proposed Participation	My Recommendation for FPL Low-Income Participation
2025	11,000	7,500	51,900
2026	11,110	7,500	51,900
2027	11,221	7,500	51,900
2028	11,333	7,500	51,900
2029	11,447	7,500	51,900
2030	11,561	7,500	51,900
2031	11,677	7,500	51,900
2032	11,793	7,500	51,900
2033	11,911	7,500	51,900
2034	12,031	7,500	51,900

Q. How does that translate to proposed goals?

A. From an FPL workpaper, attached as Exhibit MM-26, which matches that seen at Exhibit JNF-4, page 25 of 34, it can be seen that at the generator, each installation is, on average, expected to result in 0.507 kW of savings in the summer, 0.077 kW of savings in the winter, and 928.0044 kWh of savings. To calculate my proposed goals, I multiplied my proposed participants by the savings per participant, as reflected in the tables below. All values are at the Generator.

FPL Low-Income Program: Annual GWh			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	10.21	48.16	37.95
2026	10.31	48.16	37.85
2027	10.41	48.16	37.75
2028	10.52	48.16	37.64
2029	10.62	48.16	37.54
2030	10.73	48.16	37.43
2031	10.84	48.16	37.32
2032	10.94	48.16	37.22
2033	11.05	48.16	37.11
2034	11.16	48.16	37

FPL Low-Income Program: Winter MW			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	0.85	4	3.15
2026	0.85	4	3.15
2027	0.86	4	3.14
2028	0.87	4	3.13
2029	0.88	4	3.12
2030	0.89	4	3.11
2031	0.9	4	3.1
2032	0.91	4	3.09
2033	0.92	4	3.08
2034	0.92	4	3.08

FPL Low-Income Program: Summer MW			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	5.57	26.31	20.74
2026	5.63	26.31	20.68
2027	5.68	26.31	20.63
2028	5.74	26.31	20.57
2029	5.8	26.31	20.51
2030	5.86	26.31	20.45
2031	5.92	26.31	20.39
2032	5.97	26.31	20.34
2033	6.03	26.31	20.28
2034	6.09	26.31	20.22

Q. Do you have any other proposed changes to FPL's proposed goals?

A. Yes. I propose expanding its Residential HVAC/Air Condition program, which easily passes the TRC test. FPL used to have participation of over 100,000 residential customers per year in that program consistently. FPL proposes to have the number of residential customers participate in 10 years be what it used to do in two years before its goals were cut in 2014. As shown in Exhibit MM-27, FPL had over 93,000 participants in 2015, and as shown in Exhibit MM-28, had over 120,000 participants in 2014. FPL has also grown significantly since then, with many customers moving into its territory and with its expansion into Northwest Florida via its acquisition of Gulf Power Company. I think FPL can very reasonably reach 150,000 residential customers per year, and I have accordingly adjusted its goals as shown below, assuming 150,000 participants per year. FPL assumes savings of 705.6088 kWh of savings per participant, as well as 0.306 kW of savings (winter) and 0.127 kW of savings (summer) per participant (this can be seen on Exhibit JNF-4, page 23 of 34, by dividing FPL's expected savings by the projected participants). All values are at the Generator.

FPL Residential HVAC/Air Condition program: Annual GWh			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	14.11	105.89	91.78
2026	14.25	105.89	91.64
2027	14.4	105.89	91.49
2028	14.54	105.89	91.35
2029	14.69	105.89	91.2
2030	14.83	105.89	91.06
2031	14.98	105.89	90.91
2032	15.13	105.89	90.76
2033	15.28	105.89	90.61
2034	15.43	105.89	90.46

FPL Residential HVAC/Air Condition program: Winter MW			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	6.12	45.93	39.81
2026	6.18	45.93	39.75
2027	6.25	45.93	39.68
2028	6.31	45.93	39.62
2029	6.37	45.93	39.56
2030	6.44	45.93	39.49
2031	6.5	45.93	39.43
2032	6.57	45.93	39.36
2033	6.63	45.93	39.3
2034	6.7	45.93	39.23

FPL Residential HVAC/Air Condition program: Summer MW			
Year	FPL Proposed Goal	My Recommended Goal	Difference
2025	2.53	19	16.47
2026	2.56	19	16.44
2027	2.58	19	16.42
2028	2.61	19	16.39
2029	2.64	19	16.36
2030	2.66	19	16.34
2031	2.69	19	16.31
2032	2.72	19	16.28
2033	2.74	19	16.26
2034	2.77	19	16.23

Q. Have you accounted for customer growth in FPL's service territory in your proposed program goal modifications?

A. No, which makes my recommendations more conservative. If the Commission wants to account for projected customer growth, it should adjust my recommendations upwards.

Q. What are your thoughts on the Residential Low Income Renter Pilot?

A. I am glad to see that FPL is trying to address the needs of its low-income renters, which is critical to the communities we serve. Yet, I am concerned about the potential repercussions on the constituent group for which the program was created. First, the $1,000 may not be enough to upgrade to a more efficient HVAC unit, which may discourage participation. Secondly, FPL assumes that because they will pay the incremental cost of up to $1,000 for more efficient HVAC units, landlords, who still must pay for the installation cost, will not use the upgraded appliances as an excuse to shift the remaining cost onto tenants by increasing rent.

Q. What are your thoughts on FPL's industrial and commercial load-control programs?

A. As FPL itself notes, the CDR program does not pass the RIM test. This has the general body of ratepayers paying a lot of money with no apparent benefit. As shown by FPL's interrogatory answers, attached as Exhibit MM-29, customers participating in all of the commercial and industrial load-control programs have never had their electricity interrupted or curtailed within the last five years. FPL also has no intention of interrupting them in the future, as "FPL's load control programs are intended to provide capacity reserves in the event of a capacity shortfall [and] FPL does not intend to have a capacity shortfall." As such, it is hard to see the value of these programs for customers.

As shown in Exhibit MM-30, of the approximately $155 million FPL spent on energy conservation programs in 2023, almost half ($69,131,472) went to large commercial and industrial customers participating in load control programs (Commercial/Industrial Load Control, Commercial/Industrial Demand Reduction, Curtailable Load). The majority of that $155 million is going to come from residential customers. At a minimum, the credits to the participating customers should be cut in the load-control programs. Given that this is essentially free money for large commercial and industrial customers (as they never have their power cut or curtailed), I would think that they would still want to participate, even if the credits they receive are cut. I propose cutting these credits by at least half and support even deeper cuts.

Q. Please summarize your recommended goals for FPL.

A. Please see the table below for FPL's original proposed residential goals and my recommended additions.

FPL Residential Goals Summary: Annual GWh			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	39.31	129.73	169.04
2026	38.55	129.49	168.04
2027	37.9	129.24	167.14
2028	36.88	128.99	165.87
2029	36.41	128.74	165.15
2030	36.03	128.49	164.52
2031	35.71	128.23	163.94
2032	35.46	127.98	163.44
2033	35.26	127.57	162.83
2034	35.12	127.46	162.58

FPL Residential Goals Summary: Winter MW			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	19.73	42.96	62.69
2026	20.61	42.9	63.51
2027	21.7	42.82	64.52
2028	22.09	42.75	64.84
2029	22.55	42.68	65.23
2030	23.04	42.6	65.64
2031	23.57	42.53	66.1
2032	24.13	42.45	66.58
2033	24.73	42.38	67.11
2034	25.38	42.31	67.69

FPL Residential Goals Summary: Summer MW			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	25.19	37.21	62.4
2026	25.42	37.12	62.54
2027	25.8	37.05	62.85
2028	25.8	36.96	62.76
2029	25.92	36.87	62.79
2030	26.07	36.79	62.86
2031	26.26	36.7	62.96
2032	26.49	36.62	63.11
2033	26.75	36.54	63.29
2034	27.05	36.45	63.5

Q. Have you looked at Duke's proposal for its low-income programs?

A. I tried, but Duke still hasn't provided most information regarding its low-income programs, including expected participation and savings per customer. However, on May 30, 2024, Duke did provide some of its workpapers showing how its goals were derived, including the expected savings from its low-income programs, "Low Income Weatherization" and "Neighborhood Energy Saver." This information is attached to my testimony as Exhibit MM-37.

Q. Why can't you tell the expected participation and savings per customer?

A. The provided workpapers show the expected participation on a measure basis, which is sometimes on a per home basis, but is often on a per unit basis, so it is unclear how many customers Duke expects to participate in the programs (as multiple measures may apply to the same customer), and how much the average customer is thus expected to save.

Q. Have you examined Duke's historical performance in its low-income programs?

A. Yes. For its Low Income Weatherization Assistance Program, as shown in Exhibit MM-16, page 5, Duke has had less than 200 participants since 2020, and in 2023, the year with the most participation, it saved 0.4 GWh of energy (at the generator). It has done a bit better with its Neighborhood Energy Saver program, especially last year where they achieved almost 6,000 participants. Most impressive about the Neighborhood Energy Saver is the savings per customer and savings of 18.5 GWh at the generator. Duke is to be commended for the deep savings per low-income customer. But, for both programs, given that even together it has less participation than TECO, I believe there is room for expansion.

Q. What do you recommend?

A. I recommend that Duke double its goals for the Low Income Weatherization program, and increase its Neighborhood Energy Saver program by 25%. This should roughly reflect the participation that TECO already achieves in its low-income program, and it should bear mentioning that TECO is a smaller utility. These recommendations are reflected in the tables below.

Duke Low Income Weatherization Program: Annual GWh			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	1.6	3.2	1.6
2026	1.6	3.2	1.6
2027	1.7	3.4	1.7
2028	1.7	3.4	1.7
2029	1.7	3.4	1.7
2030	1.7	3.4	1.7
2031	1.7	3.4	1.7
2032	1.7	3.4	1.7
2033	1.6	3.2	1.6
2034	1.6	3.2	1.6

Duke Low Income Weatherization Program: Winter MW			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	0.5	1	0.5
2026	0.5	1	0.5
2027	0.5	1	0.5
2028	0.5	1	0.5
2029	0.5	1	0.5
2030	0.5	1	0.5
2031	0.5	1	0.5
2032	0.5	1	0.5
2033	0.4	0.8	0.4
2034	0.4	0.8	0.4

Duke Low Income Weatherization Program: Summer MW			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	0.7	1.4	0.7
2026	0.7	1.4	0.7
2027	0.8	1.6	0.8
2028	0.8	1.6	0.8
2029	0.8	1.6	0.8
2030	0.8	1.6	0.8
2031	0.8	1.6	0.8
2032	0.8	1.6	0.8
2033	0.7	1.4	0.7
2034	0.7	1.4	0.7

Duke Neighborhood Energy Saver Program: Annual GWh			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	18.9	23.6	4.7
2026	18.9	23.6	4.7
2027	19.8	24.8	5
2028	19.8	24.8	5
2029	19.8	24.8	5
2030	19.8	24.8	5
2031	19.8	24.8	5
2032	19.8	24.8	5
2033	19.8	24.8	5
2034	19.8	24.8	5

Duke Neighborhood Energy Saver Program: Winter MW			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	9	11.3	2.3
2026	9	11.3	2.3
2027	9.5	11.9	2.4
2028	9.5	11.9	2.4
2029	9.5	11.9	2.4
2030	9.5	11.9	2.4
2031	9.5	11.9	2.4
2032	9.5	11.9	2.4
2033	9.5	11.9	2.4
2034	9.5	11.9	2.4

Duke Neighborhood Energy Saver Program: Summer MW			
Year	Duke Proposed Goal	My Recommended Goal	Difference
2025	7.6	9.5	1.9
2026	7.6	9.5	1.9
2027	7.9	9.9	2
2028	7.9	9.9	2
2029	7.9	9.9	2
2030	7.9	9.9	2
2031	7.9	9.9	2
2032	7.9	9.9	2
2033	7.9	9.9	2
2034	7.9	9.9	2

Q. Please summarize your recommended goals for Duke.

A. Please see the tables below for Duke's original proposed residential goals and my recommended additions.

Duke Residential Goals Summary: Annual GWh			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	48.4	6.3	54.7
2026	48.7	6.3	55
2027	50.1	6.7	56.8
2028	50.6	6.7	57.3
2029	51.5	6.7	58.2
2030	50.8	6.7	57.5
2031	51.1	6.7	57.8
2032	51.5	6.7	58.2
2033	51.7	6.6	58.3
2034	52.1	6.6	58.7

Duke Residential Goals Summary: Winter MW			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	30.8	2.8	33.6
2026	31.3	2.8	34.1
2027	31.4	2.9	34.3
2028	32.7	2.9	35.6
2029	33.4	2.9	36.3
2030	31.9	2.9	34.8
2031	31.9	2.9	34.8
2032	31.9	2.9	34.8
2033	31.9	2.8	34.7
2034	31.9	2.8	34.7

Duke Residential Goals Summary: Summer MW			
Year	Previous Residential Goal	Additional Residential Goal	Total New Res. Goal
2025	20.1	2.6	22.7
2026	20.2	2.6	22.8
2027	20.7	2.8	23.5
2028	20.9	2.8	23.7
2029	21.1	2.8	23.9
2030	20.8	2.8	23.6
2031	20.8	2.8	23.6
2032	20.9	2.8	23.7
2033	20.9	2.7	23.6
2034	20.9	2.7	23.6

Q. Have you looked at Duke's proposals regarding its curtailable and interruptible customers?

A. Yes. I support Duke's proposed cuts. As it stands, the interruptible service and curtailable service represent almost half of Duke's spending on energy conservation. I have attached Duke's 2023 spending report as Exhibit MM-31. The Interruptible Service itself cost ratepayers $48,337,004 last year, and as residential customers represent the majority of revenue for Duke, that means most of that money is coming from residential customers. I have also attached Exhibit MM-32, which shows that these customers have not had any power interrupted or curtailed within the last five years, and Duke has no forecast for any interruptions in the future. Because Duke has sufficient resources to ensure these customers are not being interrupted or curtailed, it is hard to see the benefit of paying these customers almost $50 million a year. Therefore, I support Duke's proposal to cut the credit rates to these customers and would support even deeper cuts.

Q. What are your thoughts on TECO?

A. According to TECO's actual energy efficiency performance (pretty good by Florida standards), as I discussed earlier, TECO can achieve quite a bit of energy-efficiency savings, especially for its residential customers. I believe this should be reflected in its goals, which I have added by adjusting the target number of participants per year in what I think is an achievable way.

Q. What makes you think that your targets are achievable?

A. Many of these programs go back decades and at one point had significant participation before the 2014 goals-proceeding. If the utilities achieved robust participation before, I believe they can get to those participation numbers again (but less than they historically achieved).

Q. Do you have specific recommendations for its residential duct repair program?

A. Yes. TECO currently projects only 450 participants. In my opinion, looking at the history of the program, TECO can reach at least 1,350 participants, so it should triple the goal for this program. As shown in Exhibit MM-17, TECO had almost 1,300 participants in this program in 2016 and had almost 2,000 participants in 2015 and 2018. This recommendation is reflected in the tables below. Before the energy-efficiency goal-cuts of 2014, TECO had even more robust participation, with over 4,000 participants in 2011, as shown in Exhibit MM-33. Therefore, in my opinion, considering the number of eligible customers, a goal of 1,300 customers should be easily achievable for TECO.

TECO Residential Duct Repair: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.431	0.862	1.293
2026	0.431	0.862	1.293
2027	0.431	0.862	1.293
2028	0.431	0.862	1.293
2029	0.431	0.862	1.293
2030	0.431	0.862	1.293
2031	0.431	0.862	1.293
2032	0.431	0.862	1.293
2033	0.431	0.862	1.293
2034	0.431	0.862	1.293

TECO Residential Duct Repair: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.079	0.158	0.237
2026	0.079	0.158	0.237
2027	0.079	0.158	0.237
2028	0.079	0.158	0.237
2029	0.079	0.158	0.237
2030	0.079	0.158	0.237
2031	0.079	0.158	0.237
2032	0.079	0.158	0.237
2033	0.079	0.158	0.237
2034	0.079	0.158	0.237

TECO Residential Duct Repair: Summer MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.197	0.394	0.591
2026	0.197	0.394	0.591
2027	0.197	0.394	0.591
2028	0.197	0.394	0.591
2029	0.197	0.394	0.591
2030	0.197	0.394	0.591
2031	0.197	0.394	0.591
2032	0.197	0.394	0.591
2033	0.197	0.394	0.591
2034	0.197	0.394	0.591

Q. Do you have any recommendations for TECO's Energy and Renewable Education, Awareness, and Outreach program?

A. Yes. Looking at historical performance, I believe that TECO can double participation in the program over what it projected in its testimony, and I adjusted the goals accordingly in my recommendation, as reflected in the tables below. As shown in Exhibit MRR-1, document number 16, page 6 of 30, TECO projects 1,750 participants in the program. In 2022, as shown in Exhibit MM-17, TECO had almost 2,500 participants, and because of that, I believe that doubling the 1,750 participants is doable for TECO, which is reflected in my proposals below.

TECO Energy Education and Outreach Program: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.615	0.615	1.23
2026	0.615	0.615	1.23
2027	0.615	0.615	1.23
2028	0.615	0.615	1.23
2029	0.615	0.615	1.23
2030	0.615	0.615	1.23
2031	0.615	0.615	1.23
2032	0.615	0.615	1.23
2033	0.615	0.615	1.23
2034	0.615	0.615	1.23

TECO Energy Education and Outreach Program: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.188	0.188	0.376
2026	0.188	0.188	0.376
2027	0.188	0.188	0.376
2028	0.188	0.188	0.376
2029	0.188	0.188	0.376
2030	0.188	0.188	0.376
2031	0.188	0.188	0.376
2032	0.188	0.188	0.376
2033	0.188	0.188	0.376
2034	0.188	0.188	0.376

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TECO Energy Education and Outreach Program: Summer MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.026	0.026	0.052
2026	0.026	0.026	0.052
2027	0.026	0.026	0.052
2028	0.026	0.026	0.052
2029	0.026	0.026	0.052
2030	0.026	0.026	0.052
2031	0.026	0.026	0.052
2032	0.026	0.026	0.052
2033	0.026	0.026	0.052
2034	0.026	0.026	0.052

Q. Do you have any recommendations for the Energy Start for New Multi-Family Residences program?

A. Yes. The 300 projected participants every three years is rather weak, so I have proposed a goal of 900 participants per year. This is reflected in the tables below.

TECO Energy Start for New Multi-Family Residences: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0	1.631	1.631
2026	0	1.631	1.631
2027	0.544	1.087	1.631
2028	0	1.631	1.631
2029	0	1.631	1.631
2030	0.543	1.087	1.631
2031	0	1.631	1.631
2032	0	1.631	1.631
2033	0.544	1.087	1.631
2034	0	1.631	1.631

TECO Energy Start for New Multi-Family Residences: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0	0.198	0.198
2026	0	0.198	0.198
2027	0.066	0.132	0.198
2028	0	0.198	0.198
2029	0	0.198	0.198
2030	0.066	0.132	0.198
2031	0	0.198	0.198
2032	0	0.198	0.198
2033	0.066	0.132	0.198
2034	0	0.198	0.198

TECO Energy Start for New Multi-Family Residences: Summer MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0	0.494	0.494
2026	0	0.494	0.494
2027	0.165	0.33	0.494
2028	0	0.494	0.494
2029	0	0.494	0.494
2030	0.165	0.33	0.494
2031	0	0.494	0.494
2032	0	0.494	0.494
2033	0.165	0.33	0.494
2034	0	0.494	0.494

Q. Do you have any recommendations for TECO's residential heating and cooling program?

A. Yes. TECO projects 500 participants in Tier 1 of the program and 1000 participants in Tier 2 of the program. You can see in Exhibit MM-17, TECO had over 5,000 participants in the Residential Heating and Cooling program in

2015, before energy-efficiency programs were drastically scaled back due to the cut in energy efficiency goals from the 2014 proceeding. So, tripling the size of the program to 4,500 participants total via tripling Tier 1 and Tier 2 seems very doable. My recommended goals for the program are reflected in the tables below.

Tier 1:

TECO Residential Heating & Cooling, Tier 1: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	3.196	6.392	9.588
2026	3.196	6.392	9.588
2027	3.196	6.392	9.588
2028	3.196	6.392	9.588
2029	3.196	6.392	9.588
2030	3.196	6.392	9.588
2031	3.196	6.392	9.588
2032	3.196	6.392	9.588
2033	3.196	6.392	9.588
2034	3.196	6.392	9.588

TECO Residential Heating & Cooling, Tier 1: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	2.105	4.21	6.316
2026	2.105	4.21	6.316
2027	2.105	4.21	6.316
2028	2.105	4.21	6.316
2029	2.105	4.21	6.316
2030	2.105	4.21	6.316
2031	2.105	4.21	6.316
2032	2.105	4.21	6.316
2033	2.105	4.21	6.316
2034	2.105	4.21	6.316

TECO Residential Heating & Cooling, Tier 1: Summer MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	0.069	0.138	0.208
2026	0.069	0.138	0.208
2027	0.069	0.138	0.208
2028	0.069	0.138	0.208
2029	0.069	0.138	0.208
2030	0.069	0.138	0.208
2031	0.069	0.138	0.208
2032	0.069	0.138	0.208
2033	0.069	0.138	0.208
2034	0.069	0.138	0.208

Tier 2:

TECO Residential Heating & Cooling, Tier 2: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	6.674	13.348	20.022
2026	6.674	13.348	20.022
2027	6.674	13.348	20.022
2028	6.674	13.348	20.022
2029	6.674	13.348	20.022
2030	6.674	13.348	20.022
2031	6.674	13.348	20.022
2032	6.674	13.348	20.022
2033	6.674	13.348	20.022
2034	6.674	13.348	20.022

TECO Residential Heating & Cooling, Tier 2: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	4.262	8.524	12.786
2026	4.262	8.524	12.786
2027	4.262	8.524	12.786
2028	4.262	8.524	12.786
2029	4.262	8.524	12.786
2030	4.262	8.524	12.786
2031	4.262	8.524	12.786
2032	4.262	8.524	12.786
2033	4.262	8.524	12.786
2034	4.262	8.524	12.786

TECO Residential Heating & Cooling, Tier 2: Summer MW			
Year	Previous Program Goal	Additional Goal Summer	Total New Program Goal
2025	0.259	0.517	0.776
2026	0.259	0.517	0.776
2027	0.259	0.517	0.776
2028	0.259	0.517	0.776
2029	0.259	0.517	0.776
2030	0.259	0.517	0.776
2031	0.259	0.517	0.776
2032	0.259	0.517	0.776
2033	0.259	0.517	0.776
2034	0.259	0.517	0.776

Q. Do you have any recommendations for TECO's Neighborhood Weatherization program?

A. Yes. This program is especially important to Florida Rising's members.

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Although TECO is the undisputed leader in Florida in reaching its low-income customers with this program, and thus the benchmark that all the other utilities in this proceeding should be using to measure their progress in reaching low-income customers, I believe 10,000 participants per year is an achievable goal for TECO. In 2022, seen in Exhibit MM-17, to its credit, TECO reached 9,159 participants. This is almost as many as FPL reached, even though FPL is almost seven times the size of TECO. TECO has regularly exceeded its goal for this program, and I am happy to see that TECO has proposed to expand its goal to 7,500 participants per year to more closely reflect its actual rates of participation. But I believe TECO can do better than that, and so I propose TECO try to reach 10,000 participants per year. My recommended goal is reflected in the tables below.

TECO Neighborhood Weatherization: Annual GWh			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	10.233	3.411	13.644
2026	10.233	3.411	13.644
2027	10.233	3.411	13.644
2028	10.233	3.411	13.644
2029	10.233	3.411	13.644
2030	10.233	3.411	13.644
2031	10.233	3.411	13.644
2032	10.233	3.411	13.644
2033	10.233	3.411	13.644
2034	10.233	3.411	13.644

TECO Neighborhood Weatherization: Winter MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	2.664	0.888	3.552
2026	2.664	0.888	3.552
2027	2.664	0.888	3.552
2028	2.664	0.888	3.552
2029	2.664	0.888	3.552
2030	2.664	0.888	3.552
2031	2.664	0.888	3.552
2032	2.664	0.888	3.552
2033	2.664	0.888	3.552
2034	2.664	0.888	3.552

TECO Neighborhood Weatherization: Summer MW			
Year	Previous Program Goal	Additional Goal	Total New Program Goal
2025	1.819	0.606	2.425
2026	1.819	0.606	2.425
2027	1.819	0.606	2.425
2028	1.819	0.606	2.425
2029	1.819	0.606	2.425
2030	1.819	0.606	2.425
2031	1.819	0.606	2.425
2032	1.819	0.606	2.425
2033	1.819	0.606	2.425
2034	1.819	0.606	2.425

Q. Please summarize your recommended goals for TECO.

A. I have summarized my recommended goals for TECO in the tables below.

TECO Residential Goals Summary: Annual GWh			
Year	Previous Goal	Additional Goal	Total New Goal
2025	24.2	26.189	50.4
2026	24.2	26.189	50.4
2027	24.8	26.123	50.9
2028	24.2	26.189	50.4
2029	24.2	26.189	50.4
2030	25.2	26.123	51.3
2031	24.7	26.189	50.9
2032	24.7	26.189	50.9
2033	25.2	26.123	51.3
2034	24.7	26.189	50.9

TECO Residential Goals Summary: Winter MW			
Year	Previous Goal	Additional Goal	Total New Goal
2025	13.8	14.166	28
2026	13.8	14.166	28
2027	14.4	14.1	28.5
2028	14.3	14.166	28.5
2029	14.3	14.166	28.5
2030	15	14.1	29.1
2031	14.9	14.166	29.1
2032	14.9	14.166	29.1
2033	15	14.1	29.1
2034	14.9	14.166	29.1

TECO Residential Goals Summary: Summer MW			
Year	Previous Goal	Additional Goal	Total New Goal
2025	7.8	2.175	10
2026	7.8	2.175	10
2027	8.7	2.01	10.7
2028	8.5	2.175	10.7
2029	8.5	2.175	10.7
2030	9.5	2.01	11.5
2031	9.4	2.175	11.6
2032	9.4	2.175	11.6
2033	9.5	2.01	11.5
2034	9.4	2.175	11.6

Q. Do you have any recommendations in regards to TECO's Commercial and Industrial load control and load management programs?

A. Yes. Although TECO, unlike Duke and FPL, has actually utilized these programs to curtail demand and load, I still believe that the credits for these programs are too high. As shown in Exhibit MM-34, TECO spent $22,761,449 on its Industrial Load Management program (almost entirely in the form of credits to participating customers), $3,849,871 on its Demand Response program, and $5,153,806 on its Standby Generator program, well over half of the total $47,132,152 it spent. Residential customers, of course, account for the majority of the funding for this program. I propose that these credits be cut by at least three-quarters, if not eliminated entirely.

Q. Do you have any recommendations with regards to OUC's proposal?

A. Yes. As I mentioned earlier in my testimony, OUC has been spending most of its energy efficiency and conservation spending on commercial and industrial customers and has been neglecting its residential customers. I also recommend that OUC, at a minimum, adjust its existing programs to facilitate low-income customers being able to utilize the programs.

Q. What do you mean?

A. OUC's program that is most geared towards low-income customers is "Residential Efficiency Delivered," yet that program requires customers with less than $40,000 in income to pay 15% of the costs of any energy efficiency upgrades, as well as any amount over $2,500 (as OUC's max contribution is $2,125). Exhibit KMN-2 at page 8.

Q. Why is that an issue?

A. Many low-income customers cannot make that kind of investment. Even assuming $2,500 worth of upgrades, low-income customers would be on the hook for $375. Most low-income customers I know cannot afford to make that kind of upfront investment. According to the Federal Reserve, 37% of all adults said they would not be able to pay an emergency $400 expense using savings (https://www.federalreserve.gov/publications/2023-economic-well-being-of-us-households-in-2022-expenses.htm). I am aware that OUC allows low-income customers to repay their portion of the cost over a two-year horizon as part of their OUC bills. However, this is a burden that many low-income customers will not be willing to take on. Therefore, I recommend that for customers that make a household income of less than $60,000, OUC cover 100% of the costs of the program. Given the cost of living in the Orlando-area, based on my experience, I believe anyone with a household income of less than $60,000 is going to struggle to afford the upfront investments associated with energy-efficiency and should be considered low-income and have 100% of the costs covered by OUC.

Q. Do you have any other recommendations regarding Efficiency Delivered?

A. Yes. I recommend that the program be opened up to all of OUC's residential customers, not just those that are owners of single-family homes. Many of OUC's residential low-income customers are not owners of single-family homes, yet still have energy efficiency needs. I recommend that the goals for participation be greatly increased as well. Currently, OUC has a target of 40 measures for 2025 for Efficiency Delivered. Measures are not customers, but rather the item being used towards energy efficiency. I believe this is a crude way of tracking energy efficiency goals because OUC is not tracking how many customers it is reaching. For instance, if OUC were to give one customer three LED light bulbs, it would be considered three measures. Given that OUC is able to reach thousands of customers per year through its commercial programs, it should try to achieve something similar in its Efficiency Delivered program. I recommend multiplying its participation goal by a factor of 100 so that it tries to reach 4,000 measures in 2025 and escalates from there. Given that many OUC customers are likely to benefit from the implementation of multiple measures, this seems like a very reasonable goal. My recommendation for the goals for the program is reflected below. As the tables from Exhibit JH-16 do not have enough significant digits on energy savings for this program, I have taken a document produced in discovery to show more digits, attached as Exhibit MM-35, and have summarized my recommendations for the Efficiency Delivered program in the tables below.

OUC Efficiency Delivered: Annual GWh			
Year	OUC Proposed Goal	My Recommended Goal	Difference
2025	0.0735	7.35	7.28
2026	0.0772	7.72	7.64
2027	0.0809	8.09	8.01
2028	0.0846	8.46	8.38
2029	0.0883	8.83	8.74
2030	0.0919	9.19	9.1
2031	0.0959	9.59	9.49
2032	0.101	10.1	10
2033	0.106	10.6	10.5
2034	0.112	11.2	11.1

OUC Efficiency Delivered: Winter MW			
Year	OUC Proposed Goal	My Recommended Goal	Difference
2025	0.0119	1.19	1.18
2026	0.0126	1.26	1.25
2027	0.0133	1.33	1.32
2028	0.0141	1.41	1.4
2029	0.0148	1.48	1.47
2030	0.0155	1.55	1.53
2031	0.0162	1.62	1.6
2032	0.0171	1.71	1.69
2033	0.0181	1.81	1.79
2034	0.0192	1.92	1.9

OUC Efficiency Delivered: Summer MW			
Year	OUC Proposed Goal	My Recommended Goal	Difference
2025	0.0094	0.94	0.93
2026	0.0094	0.94	0.93
2027	0.0094	0.94	0.93
2028	0.0095	0.95	0.94
2029	0.0096	0.96	0.95
2030	0.0097	0.97	0.96
2031	0.0098	0.98	0.97
2032	0.0101	1.01	1
2033	0.0103	1.03	1.02
2034	0.0107	1.07	1.06

Q. Please summarize your recommended changes to OUC's proposed goals.

A. Please see the tables below for my recommendations regarding OUC's proposed residential goals.

OUC Residential Goals Summary: Annual GWh			
Year	OUC Proposed Goal	Additional Goal	Total New Goal
2025	1.04	7.28	8.32
2026	1.09	7.64	8.73
2027	1.15	8.01	9.16
2028	1.2	8.38	9.58
2029	1.26	8.74	10
2030	1.31	9.1	10.41
2031	1.37	9.49	10.86
2032	1.45	10	11.45
2033	1.53	10.5	12.03
2034	1.62	11.1	12.72

OUC Residential Goals Summary: Winter MW			
Year	OUC Proposed Goal	Additional Goal	Total New Goal
2025	0.18	1.18	1.36
2026	0.19	1.25	1.44
2027	0.2	1.32	1.52
2028	0.21	1.4	1.61
2029	0.22	1.47	1.69
2030	0.23	1.53	1.76
2031	0.24	1.6	1.84
2032	0.25	1.69	1.94
2033	0.27	1.79	2.06
2034	0.28	1.9	2.18

OUC Residential Goals Summary: Summer MW			
Year	OUC Proposed Goal	Additional Goal	Total New Goal
2025	0.11	0.93	1.04
2026	0.11	0.93	1.04
2027	0.11	0.93	1.04
2028	0.11	0.94	1.05
2029	0.11	0.95	1.06
2030	0.12	0.96	1.08
2031	0.12	0.97	1.09
2032	0.12	1	1.12
2033	0.13	1.02	1.15
2034	0.13	1.06	1.19

Q. Do you have any opinions regarding JEA's proposals in this case?

A. Yes. JEA is proposing to discontinue its Solar Water Heating incentive program and add two other programs: Home Efficiency Upgrades Program and Energy Efficient Products Program. These changes make sense to me, and I support these changes. However, its low-income targeted program continues to be Neighborhood Energy Efficiency, and I continue to believe there is additional room to grow this program.

Q. What do you mean?

A. As shown by Exhibit MM-18, JEA has over 100,000 customers eligible for its Neighborhood Energy Efficiency Program, growing by thousands of customers every year. Additionally, Jacksonville has an energy burden 13% higher than the national average, and 100% of its neighborhoods with high energy burdens are predominately Black and/or African-American communities. Exhibit MM-35. Yet despite these jarring stats, JEA has woefully hovered around meeting 1% of those customers every year and is on track in its current proposal to do something similar. JEA can and must do better to meet the needs of its low-income customers. Therefore, I propose JEA multiply its goal for the Neighborhood Energy Efficiency program by a factor of five. Also, I encourage JEA to consider including measures from its Home Efficiency Upgrades program and Energy Efficient Products program in its Neighborhood Energy Efficiency program. My recommendations for the goals for the Neighborhood Energy Efficiency program are reflected in the tables below.

JEA Neighborhood Energy Efficiency Program: Annual GWh			
Year	JEA Proposed Goal	My Recommended Goal	Difference
2025	1.078	5.388	4.312
2026	1.086	5.428	4.344
2027	1.094	5.468	4.376
2028	1.101	5.505	4.404
2029	1.109	5.545	4.436
2030	1.117	5.585	4.468
2031	1.125	5.625	4.5
2032	1.133	5.665	4.532
2033	1.141	5.705	4.564
2034	1.149	5.745	4.596

JEA Neighborhood Energy Efficiency Program: Winter MW			
Year	JEA Proposed Goal	My Recommended Goal	Difference
2025	0.26	1.3	1.04
2026	0.26	1.3	1.04
2027	0.26	1.3	1.04
2028	0.26	1.3	1.04
2029	0.26	1.3	1.04
2030	0.26	1.3	1.04
2031	0.27	1.35	1.08
2032	0.27	1.35	1.08
2033	0.27	1.35	1.08
2034	0.27	1.35	1.08

JEA Neighborhood Energy Efficiency Program: Summer MW			
Year	JEA Proposed Goal	My Recommended Goal	Difference
2025	0.15	0.75	0.6
2026	0.15	0.75	0.6
2027	0.15	0.75	0.6
2028	0.15	0.75	0.6
2029	0.15	0.75	0.6
2030	0.15	0.75	0.6
2031	0.15	0.75	0.6
2032	0.15	0.75	0.6
2033	0.15	0.75	0.6
2034	0.15	0.75	0.6

Q. Please summarize your recommended changes to JEA's proposed energy efficiency goals.

A. The tables below present my overall recommended residential goals for JEA based off of my proposed increase in participation in JEA's Residential Neighborhood program.

JEA Residential Goals Summary: Annual GWh			
Year	JEA Proposed Goal	Additional Goal	Total New Goal
2025	3.172	4.312	7.484
2026	3.67	4.344	8.014
2027	4.257	4.376	8.633
2028	4.917	4.404	9.321
2029	5.608	4.436	10.04
2030	6.25	4.468	10.72
2031	6.733	4.5	11.23
2032	6.951	4.532	11.48
2033	6.85	4.564	11.41
2034	6.474	4.596	11.07

JEA Residential Goals Summary: Winter MW			
Year	JEA Proposed Goal	Additional Goal	Total New Goal
2025	0.88	1.04	1.92
2026	0.99	1.04	2.03
2027	1.11	1.04	2.15
2028	1.25	1.04	2.29
2029	1.38	1.04	2.42
2030	1.51	1.04	2.55
2031	1.6	1.08	2.68
2032	1.65	1.08	2.73
2033	1.63	1.08	2.71
2034	1.57	1.08	2.65

JEA Residential Goals Summary: Summer MW			
Year	JEA Proposed Goal	Additional Goal	Total New Goal
2025	0.68	0.6	1.28
2026	0.84	0.6	1.44
2027	1.03	0.6	1.63
2028	1.26	0.6	1.86
2029	1.5	0.6	2.1
2030	1.73	0.6	2.33
2031	1.9	0.6	2.5
2032	1.96	0.6	2.56
2033	1.89	0.6	2.49
2034	1.7	0.6	2.3

Q. Please summarize your testimony.

A. Florida's electric utilities, especially the investor-owned utilities, have some of the highest residential electricity bills in the nation, with TECO and Duke leading the way and FPL not far behind. The energy efficiency being conducted in the State is terribly low compared to national averages, and Florida's refusal to engage in meaningful energy efficiency programming has not resulted in lower electricity bills or rates. In fact, quite the opposite has happened. Florida's residential electricity bills continue to climb compared to national averages, while our energy efficiency performance continues to rank towards the bottom. Given all of the energy use in Florida, there are many opportunities to increase energy efficiency programming. My testimony has focused on the residential sector, especially the low-income residential sector. I believe that my proposals are pretty conservative and modest compared to what could be achieved in a cost-effective manner. By focusing on increasing participation in programs the utilities have already proposed, I have simply proposed to increase the size of programs that the utilities have decided are cost-effective enough for their program planning and goal-setting purposes. The need in Florida for additional energy-efficiency programs, especially for low-income customers, is clear and critical. The utilities should aim for the participation levels achieved (scaled for the relative size of the respective utilities) with the savings per participant achieved by Duke. Instead of focusing the majority of funding on rebates to the largest commercial and industrial customers, which rarely, if ever, have their power interrupted (rebates mainly paid for by residential customers), funding should shift to where the need is and where the funding comes from – residential customers. For too long, residential customers have been treated as the piggy bank to fund giveaways to the largest corporate customers, even though residential customers are the ones who can least afford to be the bank. I'm here to say the piggy bank is empty and it's time to put some money back.

Q. Does this conclude your testimony?

A. Yes, it does.

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[i] Ariel Drehobl, Lauren Ross, & Roxana Ayala, American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? at 9-13 (2020), https://www.aceee.org/research-report/u2006.

[ii] Ian Livingston, *Florida is roasting in extreme heat and on pace for a record-warm year*, Washington Post (Aug. 11, 2023), https://www.washingtonpost.com/weather/2023/08/11/florida-record-heat-climate-summer/.

[iii] Nat'l Oceanic & Atmospheric Admin., *NOAA predicts above-normal 2024 Atlantic hurricane season* (May 23, 2024), https://www.noaa.gov/news-release/noaa-predicts-above-normal-2024-atlantic-hurricane-season.

(Whereupon, prefiled direct testimony of Tony Georgis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric Conservation goals by Duke Energy Florida, LLC.	**))))**	**DOCKET NO. 20240013-EG**

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 5, 2024

C19-5505

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union 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 ("PCS") 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 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. Duke Energy Florida, LLC ("Duke" or "DEF") has filed its DSM goals for the period of 2025–2034 for the Commission review and approval in this docket. Duke recommends setting its goals based on a portfolio of DSM programs that it determined are cost effective based on the Rate Impact Measure ("RIM"), Total Resource Cost ("TRC"), and Participant Cost Tests ("PCT"). The portfolio of programs is primarily based on RIM test results. However, DEF also recommends measures passing the TRC test, and the addition of low-income measures that may not meet cost-effectiveness tests but otherwise are appropriate to include.[1] Included in the DEF testimony is a proposal to change the existing Interruptible General Service ("IS") and Curtailable General Service ("CS") credit rates. However, the actual CS and IS credit rates are proposed in DEF's concurrently pending general base rate case (Docket No. 20240025-EI, the DEF "Base Rate Case"). My testimony explains why, in the context of setting DEF's five-year DSM conservation goals, the Commission should reject DEF's proposed reduction in CS and IS credits since both programs remain cost-effective.

First, my testimony explains that DEF's Ten-Year Site Plan and the embedded costs reflected in its Base Rate Case capture the historical and ongoing CS and IS capacity benefits. However, the Conservation Goals Case only evaluates DEF's proposed incremental DSM conservation goals based on a forward-looking assessment of technical and economic potential. Since DEF's proposed changes to CS and IS credits apply to both existing and new program participants, DEF's cost-effectiveness measures, and particularly the RIM test, systematically understate the value historically DEF has realized by these programs. Second, my testimony explains how DEF's chosen avoided cost generating unit does not reflect the utility's actual planned additions and retirements to its portfolio. Thus, it understates the value of DEF's proposed DSM programs. Finally, in light of the above-described issues, I recommend a refined and reasonable approach for estimating DEF's avoided capacity costs for this cycle.

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[1] Direct testimony of Tim Duff on behalf of Duke Energy Florida, LLC at 12-13.

Q. PLEASE DISCUSS THE OVERLAP BETWEEN DUKE'S CONSERVATION GOALS AND BASE RATE CASES.

A. CS and IS are distinct electric rate tariffs offered by DEF, and some form of these tariffs has been in effect for decades. The rates, credits, and terms and conditions of service under these tariffs are determined in DEF base rate cases. In my experience, most utilities typically offer some type of interruptible or non-firm service to their large commercial and industrial customers that provides recognized system reliability benefits, reduction of capacity costs, or both, and the rates, terms and conditions of that service are typically addressed in the utility's base rate cases. Further, DEF routinely recognizes the CS and IS benefits in its annual Ten-Year Site Plan filings (i.e., DEF reduces net firm load and generation reserve margin requirements for resource planning purposes by the CS and IS capacity reductions amounts). The outcomes of the Ten-Year Site Plans are then integrated into the General Rate Case as generation infrastructure investments and related costs.

At the same time, DEF's CS and IS are considered DSM measures. Consequently, the costs and revenues associated with these and other DSM measures are addressed in DEF's Energy Conservation Cost Recovery ("ECCR") clause proceedings. By evaluating only the cost effectiveness of incremental new DSM measure capacity reductions and benefits, DEF's evaluations in this docket disregard historic and ongoing system benefits provided by the large CS and IS program participants. In addition, DSM measure evaluations submitted in the Conservations Goals Case do not attempt to address certain critical program requirements and elements, including the terms and conditions associated with CS and IS service (e.g., when and how Duke can interrupt service, how much advance notice to curtail is provided [if any], potential outage frequency and duration) that are material elements affecting the benefit of the service to DEF, and the real costs (e.g., protocols for interruption events, production losses, increased maintenance, opportunity costs) that a participant must consider to enroll or remain in these programs. Thus, the credits for CS and IS service, as well as all other rates, terms and conditions, should be decided in a base rate case.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COORDINATION OF THE BASE RATE AND CONSERVATION GOALS CASES?

A. To rationally reconcile these two regulatory proceedings, Duke needs to provide the projected cost effectiveness of the CS and IS programs in this Conservation Goals Case, but all proposed changes to the tariff rates, credits, and terms and conditions of service should only be addressed in DEF Base Rate Cases where all rates, credits, and terms and conditions of service can be considered.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. My recommendations are as follows:

- **The Commission Should Consider the Ongoing Value of Existing IS and CS Participation When Establishing DEF's Demand Response Goals:**

Of the cost-effectiveness tests DEF performs, the TRC best reflects the overall value of a DSM measure to the utility system and all ratepayers. With TRC results of 16.3 for IS service and 35.1 for CS, these demand response programs have long been among the most cost-beneficial of all the Duke DSM measures.[2] The historical and ongoing value provided by the CS and IS programs to Duke is realized in reduced transmission and generation investments that are embedded in DEF's historical cost of service. This historical contribution to avoiding needed investments and ongoing benefits provided by current program participants is assumed as a given and not considered in DEF's filings in the Conservation Goals Case. DEF's proposal to adjust and reduce CS and IS credits based on outdated RIM results and disregarding the exceptionally favorable TRC results shown in DEF's own testimony, is unreasonable.

- **<u>Realistic Avoided Capacity Cost Assumptions Should Be Adopted for Application in the Conservation Goals Case:</u>**

Duke's cost-effectiveness tests are premised on a brownfield combustion turbine ("CT") in its estimate of the marginal generation costs avoided by its DSM programs.[3] There are flaws in the DEF cost estimate that materially understate the benefits of all demand response measures. Moreover, in selecting a brownfield CT as its avoided generation unit, Duke disregards how it is actually investing in and changing its generation portfolio. I recommend that a more realistic estimate of avoided costs be adopted based on updated industry estimates of the cost of a greenfield CT.

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS WHEN IMPLEMENTED?

A. The results of my recommendations are as follows:

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[2] DEF Exhibit TD-8 (Duke Energy Florida's Cost-effectiveness Tests for all DSM Programs in TRC Portfolio).

[3] DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

- Based on the exceptional TRC results that DEF estimates apply to the CS and IS service, the Commission should not assume or adopt any downward adjustment in the prevailing CS and IS credits and program costs in establishing DSM goals for DEF in this docket.
- The Commission should adopt the updated and more realistic CT avoided cost estimate described in my testimony and should find that both CS and IS service are cost effective when viewed from both RIM and TRC tests.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- TMG-1 Resume and Record of Testimony of Tony Georgis
- TMG-2 Select Duke Responses to Interrogatories
- TMG-3 Select Duke Curtailable and Interruptible Service Tariffs
- TMG-4 Duke Energy Florida, LLC's 2024 Ten-Year Site Plan
- TMG-5 Progress Energy Florida, Inc.'s 2005 Ten-Year Site Plan

III. CURTAILABLE AND INTERRUPTIBLE SERVICE CREDITS VALUE CALCULATIONS

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.[4] The DEF CS and IS programs have been in place for decades and have benefited Duke and its firm service customers by allowing them to avoid the construction of generation peaking units during that time.

IS customers must provide interruptible capacity with no limit on the number of interruptions 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.[5] 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 the interruptible capacity 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-month 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.[6]

It is important to note that interruption calls by DEF to IS participants are not limited under the tariff to the system peak hours, but could occur at any time that there is a

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4 *See* Exhibit TMG-3 at page 12 of 14 (Rate Schedule IST-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.265).

5 *Id.*

6 *See* Exhibit TMG-4 at page 33 of 135 (Schedule 3.1.1).

system need.[7] This form of non-firm service constitutes a virtual peaking or black-start generation unit. Duke controls the IS 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.[8]

Q. HOW DOES THE VIRTUAL PEAKING CAPACITY PROVIDED BY THE CS AND IS PROGRAMS COMPARE TO DEF'S EXISTING PEAKING GENERATION UNITS?

A. Currently, Duke CS and IS participants provide approximately 402 MW of almost immediately available demand reduction.[9] This highly reliable and available capacity reduction associated with the CS and IS programs is in contrast to the aging fuel-oil peaking CTs currently in DEF's generation portfolio which are rarely called upon to operate and which DEF has targeted for retirement due to their age, expense to run, and limited dispatch capability.[10] The reduced capacity need resulting from CS and IS load allows DEF to avoid the costs of constructing peaking generation in addition to other costs such as associated land costs, property taxes, siting and permitting costs, spare parts, startup testing, depreciation, dismantlement and decommissioning costs, and the costs and risks associated with failed startups that may occur with DEF's older CTs. These system benefits are the reason that CS and IS service have perennially exhibited

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7 Exhibit TMG-3 at page 9 of 14 (Rate Schedule IS-2, DEF Tariff Section No. VI, Thirtieth Revised Sheet No. 6.255).

8 *See, e.g.*, *id.* at page 3 of 14 (Rate Schedule CS-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.237).

9 Exhibit TMG-2 at pages 1-2 of 6 (Duke Response to PCS Third Request for Interrogatories No. 11).

10 *See* Exhibit TMG-4 at page 47 of 135 (Schedule 6.1).

among the highest TRC values of all Duke DSM measures. resulting in a benefit / cost ratio of 16.3 for IS and 35.1 for CS in the current Conservation Goals Case. These results are 300% to 700% higher than DSM measures targeting other retail customer segments.[11]

As discussed, Duke has complete control over the service interruption to participating IS customers, and there is no opportunity for a participating customer to avoid, or "buy through," any service interruption. Also, it is important to note is that in addition to DEF's ability to call CS and IS load reductions at any time and for any system reliability reason, the IS interruptible capacity requirements are valuable to DEF as they are instantaneous compared to required start time and ramp rate limitations of its CTs. The customer load reduction performance under the IS tariff is superior to CTs as it requires an immediate response time controlled by DEF. The result of these CS and IS tariff conditions and terms of service is an extremely reliable and flexible emergency resource for DEF built on exceptionally stringent and inflexible performance requirements for participating loads.

Q. HOW DOES DUKE ACCOUNT FOR THE CS AND IS LOADS IN ITS GENERATION RESOURCE PLANNING AND TEN-YEAR SITE PLANS?

For resource planning purposes, Duke has not in the past and does not currently treat the full measured demand and loads of CS and IS customers as firm loads that must be served by its generation resources. This is clearly documented and calculated in the Ten-Year Site Plan filings, which deduct the CS and IS capacity values from the

[11] DEF Exhibit TD-8 (Cost-effectiveness Tests for all DSM Programs in TRC Portfolio).

determination of Net Firm Demand upon which Duke calculates its capacity reserve margins and generation capacity requirements.[12] In the 2024 Ten-Year Site Plan, Duke cites 402 MWs of available interruptible capacity reductions to the Net Firm Demand requirements for 2024 and realized between 232 to 476 MWs of capacity reductions in the last 10 years.[13] Based on the past Ten-Year Site Plans, CS and IS participants have provided a continuous source of avoided generation capacity need, system reliability benefits, and cost savings to Duke and all firm service customers for multiple decades.[14]

Q. WHAT IS THE TOTAL CAPACITY NEED THAT DUKE HAS AVOIDED THROUGH THE CS AND IS PROGRAMS?

A. Duke's generation and transmission systems are designed and constructed to meet expected net firm peak demands on the utility system plus a reserve margin. The CS and IS programs have allowed Duke to avoid or defer additional transmission and generation investments over the years in which the programs have been active.

In Florida and for Duke, the accepted capacity reserve margin for resource planning purposes is 20%.[15] Thus, the capacity 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 required reserve margin. For example, as 402

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12 Exhibit TMG-4 at 33 of 135 (Schedule 3.1.1).

13 *Id*.

14 *See, e.g.*, Exhibit TMG-5 at pages 30-32 of 102 (Progress Energy Florida, Inc.'s 2005 Ten-Year Site Plan).

15 Exhibit TMG-4 at page 112 of 135.

MWs are available for CS and IS capacity reductions in the 2024 Ten-Year Site Plan, the actual benefit to Duke including the 20% reserve margin is 482 MWs.[16]

Q. ARE THESE HISTORIC AVOIDED COST BENEFITS CONSIDERED IN THE CONSERVATION GOALS PROCEEDINGS?

A. No. In fact, DEF witness Herndon assumed continued existing CS and IS participation as a given remaining at current levels (*i.e.* he did not assess the benefits provided by current participants, but simply presumed that current levels of participation continue).[17] The system benefits provided through the years by existing program participants are, however, effectively captured in DEF's Base Rate Case proceeding through embedded generation and transmission costs that are shown in its cost of service analysis. These production and transmission costs in the DEF Base Rate Case are reduced because of CS and IS participation.

In short, looking only at marginal future program benefits, as DEF does in its DSM Goals filing, does not accurately capture the benefits DEF actually realizes from the programs. In the context of this docket, this helps to explain why there is a such a dramatic disparity between RIM and TRC cost/benefit calculations for these programs. DEF correctly proposes to continue the highly successful CS and IS programs, but its proposal to change the level of credits based solely on outdated RIM results, is

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[16] 402 MW x 120% = 482.4 MW

[17] *See* Exh. TMG-2 at page 5 of 6 (DEF's Response to PCS Phosphate's Fifth Set of Interrogatories (No. 17)).

inappropriate. It is important to note that DEF's projection of DSM program costs through the year 2030 assumes no reduction in CS or IS incentive payments.[18]

Q. PLEASE EXPLAIN FURTHER.

A. Duke's approach calculates avoided future costs to assess projected benefits to incremental new program participation, but then applies that estimated marginal benefit to both existing and future participation when existing participants are contractually committed through the multiple test years of the pending Base Rate Case. In addition to the avoided cost calculation errors described below, excessive reliance on the RIM test for setting program goals largely disregards the significant and on-going system benefits that are recognized in the TRC test.

Q. HOW SHOULD THE VALUE OF CS AND IS SERVICE BE RESOLVED?

A. The solution should be twofold.

- First, for the purpose of setting DEF's DSM goals for the coming cycle, the RIM and TRC tests are equally relevant for the Duke CS and IS programs. Looking at both measures, it is apparent that both measures are highly cost-effective and beneficial and no reduction in the existing credits should be assumed.
- Second, any prospective adjustment to CS and IS credits should be determined in DEF Base Rate Cases where all other elements of the rates and terms and conditions of those tariffs are evaluated and approved.

[18] *Id.*

IV. AVOIDED CAPACITY COSTS ASSUMPTIONS

Q. HOW DOES DUKE USE AVOIDED COSTS FROM DSM PROGRAMS IN ITS CONSERVATION GOALS RECOMMENDATIONS?

A. Duke's Conservation Goals proceeding and recommendation of programs utilize cost/benefit analyses premised upon future benefits of avoiding marginal new capacity costs. Duke elected to calculate that avoided marginal generation cost based on the construction of a brownfield natural gas CT entering commercial service in 2029. Duke estimates the avoided generating unit costs for the construction of a brownfield CT at $735.20 per kilowatt ("kW") which includes transmission interconnection costs.[19]

Q. IS DEF'S SELECTION OF A BROWNFIELD CT ENTERING SERVICE IN 2029 REPRESENTATIVE OF ITS AVOIDED GENERATION CAPACITY COSTS?

A. No. DEF's most recent 2024 Ten-Year Site Plan reveals that over the next five years the utility plans significant capacity additions, none of which involve new CTs. In fact, DEF's basic plan, as noted above, involves retiring more than 500 MWs of existing oil-fueled CTs that are older, expensive to run, and maintain and operate at exceptionally low capacity factors.[20] Duke plans to replace that capacity with 14 solar projects comprising more than 1,000 MWs of nameplate capacity as well as uprates to its gas-fired combined cycle facility capacity.[21] Because all the planned individual solar projects are rated at less than 75 MWs, there will be no finding of a capacity need by

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19 DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

20 Exhibit TMG-4 at page 69 & 75-76 of 135 (Schedule 8).

21 *Id.*

the Commission for those resources per Section 403.503(14), Florida Statutes. In short, DEF's actual avoidable generation investment lies in its significant new generation additions over the next five years, and the more than 400 MWs of existing CS and IS demand response effectively support the retirement of the older oil-burning CTs through lowering DEF's reserve margin requirements.

Q. WHAT OTHER ISSUES HAVE YOU IDENTIFIED WITH DUKE'S FUTURE AVOIDED COSTS ASSUMPTIONS?

A. Duke's assumption of a brownfield CT for avoided generation capacity selects the cheapest resource to be built on the DEF system over the next decade while disregarding the billions in other capacity additions that it plans to make. Additional energy efficiency and demand response should be far more cost effective for DEF ratepayers than the other fossil-fueled and non-fossil-fueled generation included in the Ten-Year Site Plan, such as limited summer capacity additions attributed to the solar additions.

Q. IS THERE A DIFFERENCE IN THE CAPITAL COSTS, AND THUS THE AVOIDED COSTS, ASSOCIATED WITH THESE FOSSIL-FUELED AND NON-FOSSIL-FUELED RESOURCES IDENTIFIED IN DUKE'S TEN-YEAR SITE PLAN?

A. Yes. As shown below, the potential avoided costs of the generation resources Duke uses to meet its load and required 20% reserve margin vary significantly.

- Brownfield CT $735.20 per kW[22]
- Greenfield CT $949.40 per kW[23]
- Solar $1,222 per kW[24]
- Storage $1,650 per kW[25]
- Solar with Storage $2,471 per kW[26]

Q. WHAT IS YOUR RECOMMENDATION FOR DEF'S AVOIDED GENERATING UNIT COSTS IN THE CONSERVATION GOALS CASE?

A. To reconcile the significant disconnect between DEF's claimed avoided unit in this docket and the proposed generation investments over the next five years, I recommend that DEF treat its avoided unit for the purposes of the Conservation Goals Case as a greenfield CT beginning operation in 2027, which is the year the last Debary distillate oil CT is scheduled to retire. Rather than treat the planned solar additions or combined cycle unit costs as the avoided unit, an approach using a greenfield CT would be an appropriate compromise and would align with other utilities' avoided generation unit costs.

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[22] DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

[23] *Id.*

[24] Exhibit TMG-4, page 77 of 135 (Mule Creek Commercial in-service date of 3/2024).

[25] *Id.* at page 87 of 135 (TBD Battery Storage in-service date of 3/2027).

[26] *Id.* at page 91 of 135 (TBD Photovoltaic with Battery Storage in-service date of 7/2028).

Q. DO OTHER FLORIDA UTILITIES UTILIZE A SIMILAR GENERATION UNIT IN THEIR ASSUMPTION OF AN AVOIDED GENERATION UNIT COST?

A. Yes. Tampa Electric ("TECO") utilizes a natural gas-fired reciprocating engine for its avoided unit data in its Conservation Goals proceeding. TECO estimates the costs for the avoided generation unit at $1,278.92 per kW, which is 74% higher than Duke's brownfield CT assumption.[27] In addition, Florida Power and Light's ("FP&L") estimate for an avoided generation unit in its Conservation Goals proceeding is based on a combined-cycle ("CC") unit.[28] I estimate the construction cost of such a unit to be $1,221 per kW using National Renewable Energy Laboratory ("NREL") Annual Technology Baseline report.[29]

Q. WHAT ARE REASONABLE ASSUMPTIONS CONCERNING THE EXPECTED COST OF A GREENFIELD CT FOR DUKE?

A. Duke's Conservation Goals Case identifies the capital costs for construction of a greenfield CT at $949.40 per kW in 2034.[30] Further, this estimate is in line with the current NREL's Annual Technology Baseline report which assesses normalized

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27 Docket No. 20240014-EG, *In re: Commission review of numeric conservation goals of Tampa Electric Company*, Exhibit No. MRR-1 Document No. 10, p. 1 of 1.

28 Docket No. 20240012-EG, *In re: Commission review of numeric conservation goals of Florida Power & Light Company*, Direct Testimony of Andrew Whitley on behalf of Florida Power & Light Company, p. 19.

29 National Renewable Energy Laboratory ("NREL"), 2023 Annual Technology Baseline Report, *available at* https://data.openei.org/files/5865/2023-ATB-Data_Master_v9.0.xlsx (Tab "Natural Gas FE," cell P112 (showing the capex required for a 2024 advanced natural gas combined cycle advanced)) (hereafter "NREL 2023 ATB Report").

30 DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

technology costs for power generation. The NREL report estimates the capital costs for a CT at $1,102.60 per kW in 2024.[31]

Q. WHAT IS YOUR RECOMMENDATION REGARDING DUKE'S AVOIDED GENERATOR COST ASSUMPTION?

A. I recommend that Duke replace its existing avoided generation unit cost assumption with a greenfield CT or similar technology to more accurately reflect marginal new generation it would construct to serve growing load. This approach is more realistic and would also align Duke with comparable avoided unit assumptions by the other Florida investor-owned utilities. Based on the benchmarking and Duke's own data, a cost of $949.40 per kW should be utilized and should replace the existing brownfield CT cost assumption of $735.20.

Q. WHAT IS THE IMPACT OF INCREASING THE AVOIDED GENERATION COST ASSUMPTION ON THE CONSERVATION GOALS AND DSM PROGRAM ANALYSES?

A. Applying a higher and more representative cost for an avoided generating unit will enhance the expected cost effectiveness of DEF demand response measures under both the RIM and TRC tests. I recommend that the Commission more heavily weight TRC results when assessing mature and established demand response measures for the purposes of setting DEF's DSM goals, assuming that all prevailing demand response incentive payments remain at prevailing levels unless adjusted prospectively in a DEF Base Rate Case.

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31 NREL 2023 ATB Report (Tab "Natural Gas FE," cell P109 (showing 2024 advanced natural gas combustion turbine)).

Q. CAN YOU RECALCULATE THE DSM PROGRAM COST/BENEFIT ANALYSIS INCLUDED IN MR. DUFF'S EXHIBIT TD-6?

A. No. I cannot recalculate or adjust variables in the DSM program analysis and modeling as Duke would not provide a working model or workpapers to perform adjustments. I requested the workpaper used to generate the results including the RIM, Total Participant, and TRC tests; however, Duke only provided a Microsoft Excel spreadsheet with hard-coded numbers for the total benefits and costs related to the programs.[32]

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

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[32] *See* Exh. TMG-2 at page 4 of 6 (DEF's Response to PCS Phosphate's Third Request for Production of Documents No. 5).

(Whereupon, prefiled direct testimony of Steven W. Chriss was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	**: : :**	**DOCKET NO. 20240012-EG**
In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC).	**: : :**	**DOCKET NO. 20240013-EG**
In re: Commission review of numeric conservation goals (Tampa Electric Company).	**: : :**	**DOCKET NO. 20240014-EG**
In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	**: : :**	**DOCKET NO. 20240015-EG**
In re: Commission review of numeric conservation goals (JEA).	**: :**	**DOCKET NO. 20240016-EG**
In re: Commission review of numeric conservation goals (Orlando Utilities Commission).	**: : : :**	**DOCKET NO. 20240017-EG** **FILED: June 5, 2024**

DIRECT TESTIMONY AND EXHIBITS OF

STEVE W. CHRISS

ON BEHALF OF

WALMART INC.

C20-6054

Contents

Exhibits

Exhibit SWC-1: Witness Qualifications Statement

Exhibit SWC-2: U.S. Energy Information Administration, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," Table 1-2

C20-6055

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72716-0550. I am employed by Walmart Inc. ("Walmart") as Senior Director, Utility Partnerships.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Walmart.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to Director, Energy and Strategy Analysis in October 2016 and the position was re-titled in October 2018. I was promoted to my current position in July 2023. My Witness Qualifications Statement is attached as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I testified in Docket Nos. 20110138-EI, 20120015-EI, 20130140-EI, 20130040-EI, 20140002-EI, 20160021-EI, 20160186-EI, 20190061-EI, 20200067-EI, 20200069-EI, 20200070-EI, 20200071-EI, 20200092-EI, 20200176-EI, and 20210015-EI.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 270 proceedings before 42 other utility regulatory commissions. I have also submitted testimony before legislative committees in six states. My testimony has addressed topics including, but not limited to, cost of service and rate design, return on equity, revenue requirements, ratemaking policy, net metering, community solar, large customer renewable programs, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN FLORIDA.

A. As shown on Walmart's website, Walmart operates 386 retail units, nine distribution centers, and two fulfillment centers and employs over 118,000 associates in Florida. In fiscal year ending 2024, Walmart purchased $8.5 billion worth of goods and services from Florida-based suppliers, supporting over 82,000 supplier jobs.[1]

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN EACH UTILITY'S SERVICE TERRITORY.

A. Walmart's operations within each utility's service territory is as follows:

- Walmart has 179 stores and clubs, four distribution centers, and related facilities that take service from Florida Power & Light Company ("FPL"). Walmart participates in the Commercial/Industrial Demand Reduction ("CDR") program and in the past has participated in energy efficiency rebates with FPL.
- Walmart has 93 stores and clubs, one distribution center, and related facilities that take service from Duke Energy Florida, LLC ("DEF"). Walmart participates in the Interruptible Service Program and in the past has participated in energy efficiency rebates with DEF.
- Walmart has 36 stores and clubs, one distribution center, and related facilities that take service from Tampa Electric Company ("TECO"). Walmart has participated in energy efficiency rebates with TECO.
- Walmart has 23 stores, clubs, and related facilities that take service from JEA. Walmart has participated in energy efficiency rebates with JEA.
- Walmart has 13 stores, clubs, and related facilities that take service Orlando Utilities Commission ("OUC"). Walmart has participated in energy efficiency rebates with OUC.

[1] https://corporate.walmart.com/about/location-facts/united-states/florida

- Walmart has two stores that take electric service from Florida Public Utilities Company ("FPUC"). Walmart has not participated in any FPUC programs since 2018, the farthest back that data is available.

Q. HAS WALMART ESTABLISHED CORPORATE RENEWABLE ENERGY AND SUSTAINABILITY GOALS?

A. Yes. Walmart has long had ambitious and significant company-wide renewable energy goals, and on September 21, 2020, Walmart announced new targets as a part of its sustainability goals, including: (1) to be supplied 100 percent by renewable energy by 2035 and (2) zero carbon emissions in its operations, including its transportation fleet vehicles, without the use of offsets, by 2040. Walmart has also set a goal to transition to zero emission buildings by deploying low-impact refrigerants for cooling and electric equipment for heating by 2040.[2] Additionally, on January 9, 2024, Walmart announced a goal to bring 10 GW of new clean energy projects online by the end of 2030, including 1 GW of new on-site solar plus storage, and enabling 2 GW of new community solar projects.[3] Walmart's goal to be carbon free by 2040 includes shifting away from fossil fuel powered fleet vehicles to alternative fuel powered vehicles that do not emit carbon during their operation. When considering Walmart's fleet and its commitment to eliminate carbon emissions, it is worth noting that Walmart owns one of the largest private fleets in the United States.

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[2] *Walmart Sets Goal to Become a Regenerative Company*, Walmart (Sept. 21, 2020), https://corporate.walmart.com/newsroom/2020/09/21/walmart-sets-goal-to-become-a-regenerative-company.
[3] *Walmart Keynote at CES 2024*, Walmart (Jan. 9, 2024), https://tech.walmart.com/content/dam/walmart-global-tech/documents/Walmart%20CES%20Keynote%20Script%20Transcript_1.9.24.pdf.

Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the demand-side management ("DSM") goals filings of the Utilities[4] ("Goals Dockets") and to provide recommendations to the assist the Commission in its thorough and careful consideration of the customer impacts of the Utilities' requests. For the purposes of these Goals Dockets, Walmart will focus on the proposals put forth by FPL, DEF, and TECO.

Q. PLEASE SUMMARIZE WALMART'S RECOMMENDATIONS TO THE COMMISSION.

A. Walmart's recommendations to the Commission are as follows:

1) For the purposes of FPL's Goals Docket, Walmart does not take a position on FPL's proposed goals as they pertain to commercial and industrial ("C&I") programs, and does not oppose FPL's proposed C&I programs. Walmart does not take a position on FPL's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

2) For the purposes of DEF's Goals Docket, the Commission should reject DEF's proposed change to the credits for Interruptible General Service (IS-2 and IST-2), Curtailable General Service (CS-2, CS-3, CST-2, and CST-3), and General Service – Load Management – Standby Generation (GSLM-2). Walmart takes no position on DEF's proposed goals as they pertain to C&I programs, and otherwise does not oppose DEF's proposed C&I programs. Walmart does not

[4] "Utilities" collectively refers to FPL, DEF, TECO, FPUC, JEA, and OUC.

take a position on DEF's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

3) For the purposes of TECO's Goals Docket, Walmart does not take a position on TECO's proposed goals as they pertain to C&I programs, and does not oppose TECO's proposed C&I programs. Walmart does not take a position on TECO's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE UTILITIES INDICATE WALMART'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any of the Utilities' filed positions.

Utility Proposed Goals and Programs

Florida Power & Light Company

Q. WHAT IS YOUR UNDERSTANDING OF FPL'S PROPOSED DSM GOALS IN ITS GOALS DOCKET?

A. My understanding is that FPL proposes combined residential, commercial, and industrial goals of 408 summer MW, 316 winter MW, and 885 GWh cumulative energy reduction for the 2025-2034 period.[5]

[5] *See* Direct Testimony of John N. Floyd, page 6, line 16 to line 19.

Q. WHAT IS YOUR UNDERSTANDING OF THE C&I PROGRAMS PROPOSED BY FPL IN ITS GOALS DOCKET?

A. My understanding is that FPL proposes the following programs:

- Business HVAC
- Business Lighting
- CDR
- Business Custom Incentive
- Business On Call.[6]

Q. DOES FPL PROPOSE ANY CHANGES TO THE CDR OR COMMERCIAL INDUSTRIAL LOAD CONTROL ("CILC") BILL CREDITS IN ITS GOALS DOCKET?

A. No, as the Settlement Agreement in FPL's 2021 Base Rate Case, Docket No. 20210015-EI, limits modifications to the CDR and CILC bill credits.[7]

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION IN REGARD TO FPL'S PROPOSALS?

A. For the purposes of FPL's Goals Docket, Walmart does not take a position on FPL's proposed goals as they pertain to C&I programs, and does not oppose FPL's proposed C&I programs. Walmart does not take a position on FPL's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

[6] *Id.*, page 29, line 1 to line 6.
[7] *Id.*, page 36, line 12 to line 16.

Duke Energy Florida, LLC

Q. WHAT IS YOUR UNDERSTANDING OF DEF'S PROPOSED DSM GOALS IN ITS GOALS DOCKET?

A. My understanding is that DEF proposes combined residential, commercial, and industrial goals of 291 summer MW, 362 winter MW, and 561 GWh cumulative energy reduction for the 2025-2034 period.[8]

Q. WHAT IS YOUR UNDERSTANDING OF THE C&I PROGRAMS PROPOSED BY DEF IN ITS GOALS DOCKET?

A. My understanding is that DEF proposes the following programs:

- Smart $aver Business
- Interruptible Services Program
- Curtailable Services Program
- Standby Generation Program.[9]

Q. DOES DEF PROPOSE ANY CHANGES TO THE INTERRUPTIBLE AND CURTAILABLE SERVICE CREDIT RATES?

A. Yes. DEF proposes changes to the credit rates for Interruptible General Service (IS-2 and IST-2), Curtailable General Service (CS-2, CS-3, CST-2, and CST-3), and General Service – Load Management – Standby Generation (GSLM-2).[10]

[8] *See* Direct Testimony of Tim Duff, page 10, Table 1.
[9] *See id.* at Exhibit TD-7.
[10] Direct Testimony of Tim Duff, page 22, line 3 to line 8.

Q. WHY DOES DEF PROPOSE THIS CHANGE?

A. DEF states that the credit changes "…will allow DEF to maintain the cost-effectiveness results for the offerings that were included in the 2019 DSM goals docket filing."[11]

Q. WHAT IS YOUR UNDERSTANDING OF THE COST EFFECTIVENESS TEST RESULTS FOR THE INTERRUPTIBLE AND CURTAILABLE SERVICES PROGRAMS?

A. My understanding is that the Rate Impact Measure ("RIM") test result for the interruptible services program is 1.38 and the Total Resource Cost ("TRC") test result is 16.33. Similarly, the RIM test result for the curtailable services program is 2.16 and the TRC test result is 35.12.[12] A result for either test above 1.00 indicates that the benefits of the program exceed the costs of the program, so both programs have benefits that significantly exceed the costs of the programs.

Q. IS WALMART CONCERNED THAT THE BENEFITS MAY BE UNDERSTATED?

A. Yes. If the benefits are understated, then reducing the credit, and potentially impacting customer deployment of dispatchable distributed energy resources ("DER") to support grid reliability and resilience, may not be an appropriate change to the program. An examination of the underlying avoided generation assumptions used by DEF suggests that DEF may use a value that is too conservative for base year avoided generating unit cost.

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[11] *Id.*
[12] *See id.* at Exhibit TD-8, page 2.

Q. WHAT BASE YEAR AVOIDED GENERATING UNIT COST DOES DEF USE?

A. DEF uses $735.20/kW for the combustion turbines, including transmission upgrade cost.[13]

Q. IS THIS VALUE LOWER THAN RECENTLY PUBLISHED ESTIMATES OF COMBUSTION TURBINE COSTS?

A. Yes. In January 2024, the United States Energy Information Administration ("EIA") released "Capital Cost and Performance Characteristics for Utility-Scale Power Generating Technologies," which estimates the capital cost of $836/kW for a simple cycle combustion turbine.[14] While Walmart has not performed an independent analysis comparing DEF's calculation to that published by EIA, the difference between the two values creates concern that DEF understates the cost of building a combustion turbine.

Q. DOES WALMART HAVE ADDITIONAL HIGH-LEVEL CONCERNS ABOUT DEF'S ASSUMPTIONS?

A. Yes. First, DEF utilizes a generator cost escalation rate of -1.09 percent for 2023 to 2032.[15] While this is not inconsistent with published historical trends in combustion turbine levelized cost of energy per Lazard,[16] a business advisory firm that publishes annual estimates of levelized costs of energy for a number of generation technologies, it should nonetheless be thoroughly examined by the Commission.

Second, DEF does not include any benefits for 2025 through 2028 for the interruptible services program, suggesting that DEF does not foresee any need for

[13] *See id. at* Exhibit TD-4.
[14] *See* Exhibit SWC-2.
[15] *See* Direct Testimony of Tim Duff at Exhibit TD-4.
[16] *2023 Levelized Cost of Energy+*, Lazard, page 9 (Apr. 12, 2023), https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

generation, transmission, or distribution capital costs that could be avoided with the program for that period of time.[17] However, Duke Energy Corporation, DEF's parent company, stated in its first quarter earnings review that its Carolinas and Florida business units have seen 2.4 percent customer growth, and Duke Energy Corporation projects total load growth of 1.5 to 2 percent for 2023 to 2028.[18] With the caveat that DEF's experience may differ from its sister companies, the Commission should thoroughly examine the assumption that no capital costs will be required, and recognize that customer-sited solutions incentivized by the interruptible services program can help to offset generation, transmission, and distribution investment that would otherwise be required to meet load growth.

Q. DO CUSTOMER-DEPLOYED DERs INCENTIVIZED BY PROGRAM PARTICIPATION BRING ADDITIONAL BENEFITS TO FLORIDA'S UTILITY SYSTEMS BEYOND THE PROGRAM REQUIREMENTS?

A. Yes, particularly during hurricanes or other extreme weather events. A customer-sited dispatchable DER, whether operating alone or within a microgrid, may help reduce restoration costs by essentially allowing one or more customers to be self-sufficient during the restoration process. Restoring power after a severe weather event like a hurricane is typically an extensive process that requires the utility to prioritize areas that are impacted by an outage and dispatch their field personnel accordingly. If a portion of the utility's large customers are being supplied by power independently, it

[17] *See* Direct Testimony of Tim Duff at Exhibit TD-6, page 16.
[18] *Q1/2024 Earnings Review and Business Update*, Duke Energy (May 7, 2024), https://s201.q4cdn.com/583395453/files/doc_financials/2024/q1/Q1-2024-Earnings-Presentation_vF-w-Reg-G.pdf.

allows the utility to focus its efforts on other areas. Providing a utility with this type of "breathing room" gives the utility flexibility to mobilize more cost-efficient restoration plans that may not otherwise be available.

From the perspective of a large commercial customer who has extensive operational experience during and after hurricanes in Florida, it is Walmart's experience that utility personnel who are responsible for visiting sites and restoring the grid require various supplies ranging from water to cell phones. It is important to Walmart that it has the operational ability to serve these needs in order to ensure that field personnel have what is required to restore the transmission and distribution systems and turn the electricity back on for everyone.

Q. ARE THERE ADDITIONAL BENEFITS OF CUSTOMER-DEPLOYED DER TO FLORIDA'S COMMUNITIES, AS WELL?

A. Yes. It is not just utility employees who turn to Walmart and other large commercial customers for necessary supplies. Walmart strives to be a leader in caring for the needs of communities during times of tremendous hardship, like a hurricane or other severe weather event. This includes providing supplies to first responders, shelters, and citizens who live in the area and need every day basics to live. For retail customers, the customer-deployed DER incentivized by the Interruptible General Service and Curtailable General Service programs, and similar programs offered by FPL, TECO, and others, can help to bring these additional benefits to Florida communities.

C20-6067

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION IN REGARD TO DEF'S PROPOSALS?

A. For the purposes of DEF's Goals Docket, the Commission should reject DEF's proposed change to the credits for Interruptible General Service (IS-2 and IST-2), Curtailable General Service (CS-2, CS-3, CST-2, and CST-3), and General Service – Load Management – Standby Generation (GSLM-2). Walmart takes no position on DEF's proposed goals as they pertain to C&I programs, and otherwise does not oppose DEF's proposed C&I programs. Walmart does not take a position on DEF's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

Tampa Electric Company

Q. WHAT IS YOUR UNDERSTANDING OF TECO'S PROPOSED DSM GOALS IN ITS GOALS DOCKET?

A. My understanding is that TECO proposes goals of 149 summer MW, 197 winter MW, and 451 GWh cumulative energy reduction for the 2025-2034 period.[19]

Q. WHAT IS YOUR UNDERSTANDING OF THE C&I PROGRAMS PROPOSED BY TECO IN ITS GOALS DOCKET?

A. My understanding is that TECO proposes the following programs:

- Commercial/Industrial Audit (free)
- Comprehensive Commercial/Industrial Audit (paid)
- Cogeneration

[19] *See* Direct Testimony of Mark R. Roche, page 11, line 6 to line 9.

- Commercial/Industrial Custom Energy Efficiency
- Demand Response
- Industrial Load Management (GSLM 2&3)
- Lighting Conditioned Space
- Lighting Non-Conditioned Space
- Lighting Occupancy Sensors
- Commercial Load Management (GSLM 1)
- Standby Generator
- VFD and Motor Controls
- Commercial Heat Pump Water Heater and Drain Water Heat Recovery
- Conservation Research and Development
- Renewable Energy Program ("Sun-to-Go").[20]

Q. DOES TECO PROPOSE ANY CHANGES TO THE LOAD MANAGEMENT BILL CREDITS IN ITS GOALS DOCKET?

A. No, as TECO's load management bill credits are set by a stipulated agreement.[21]

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION IN REGARD TO TECO'S PROPOSALS?

A. For the purposes of TECO's Goals Docket, Walmart does not take a position on TECO's proposed goals as they pertain to C&I programs, and does not oppose TECO's proposed C&I programs. Walmart does not take a position on TECO's proposed goals as they pertain to residential programs, nor on the proposed residential programs.

[20] *Id.*, page 22, line 16 to page 23, line 7.
[21] *See* Direct Testimony of Mark R. Roche at Exhibit No. MRR-1, page 22.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

C20-6070

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 21st day of August, 2024.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028