BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240025-EI

Petition for rate increase
by Duke Energy Florida.
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VOLUME 1
PAGES 1 - 222

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 21, 2024

TIME: Commenced: 11:00 a.m.
Concluded: 1:30 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
TALLAHASSEE, FLORIDA
(850) 894-0828

APPEARANCES:

DIANNE TRIPLETT, MATTHEW R. BERNIER and STEPHANIE A. CUELLO, ESQUIRES, 106 E. College Avenue, Suite 800, Tallahassee, Florida 32301; appearing on behalf of Duke Energy Florida, LLC (DEF).

WALT TRIERWEILER, PUBLIC COUNSEL, CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL, PATRICIA A. CHRISTENSEN, MARY ALI WESSLING, AUSTIN WATROUS and OCTAVIO PONCE, ESQUIRES, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida (OPC.).

FRED ASCHAUER, ESQUIRE, Lewis, Longman & Walker, 106 East College Ave., Suite 1500, Tallahassee, Florida 32301; appearing on behalf of Americans for Affordable Clean Energy, Circle K, RaceTrac and Wawa, (FUEL RETAILERS).

JON C. MOYLE, JR., SERENA MOYLE and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, FL 32301; appearing on behalf of Florida Industrial Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT, ESQUIRE, 1300 Thomaswood Drive, Tallahassee, Florida 32308; appearing on behalf of Florida Retail Federation (FRF).

APPEARANCES CONTINUED:

BRADLEY MARSHALL and JORDAN LUEBKEMANN, ESQUIRES, Earthjustice, 111 S. Martin Luther King Jr. Boulevard, Tallahassee, Florida 32301; and HEMA LOCHAN, ESQUIRE, Earthjustice, 48 Wall Street, 15th Floor, New York, New York 10005; appearing on behalf of Florida Rising (Florida Rising) and League of United Latin American Citizens of Florida (LULAC).

PETER J. MATTHEIS, MICHAEL K. LAVANGA and JOSEPH R. BRISCAR, ESQUIRES, Stone Mattheis, Xenopoulos & Brew, 1025 Thomas Jefferson Street, NW, Suite 800 West, Washington, DC 20007; appearing on behalf of Nucor Steel (NUCOR).

JAMES W. BREW, LAURA W. BAKER and SARAH NEWMAN, ESQUIRES, Stone Law Firm, 1025 Thomas Jefferson Street NW, Suite 800 West Washington, DC 20007; appearing on behalf of Florida White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate - White Springs (PCS).

WILLIAM C. GARNER, ESQUIRE, Law Office of William C. Garner, PLLC, 3425 Bannerman Road, Unit 105, No. 414, Tallahassee, Florida 32312; appearing on behalf of Sierra Club (Sierra Club) and Southern Alliance for Clean Energy (SACE).

APPEARANCES CONTINUED:

STEPHANIE U. EATON, ESQUIRE, Spilman Thomas & Battle, PLLC, 110 Oakwood Drive, Suite 500, Winston-Salem, North Carolina 27103; STEVEN W. LEE, ESQUIRE, Spilman, Thomas & Battle, PLLC, 1100 Bent Creek Boulevard, Suite 101, Mechanicsburg, Pennsylvania 17050; appearing on behalf of Walmart, Inc. (Walmart).

SHAW STILLER, MAJOR THOMPSON and JENNIFER CRAWFORD, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	38	39
2-274	As identified in the CEL	38	39

P R O C E E D I N G S

COMMISSIONER GRAHAM: Good morning, everyone. I am not quite sure -- I think our Chairman is tied up somewhere, but we can go through some of this introductory stuff.

We will convene this hearing. Let the record show it is August 21st. It is seven after 11:00, and, staff, if I can get you to read the notice, please.

MR. STILLER: By notice dated August 7th, 2024, this time and place has been set for a hearing in Docket No. 20240025-EI. The purpose of this hearing is more fully set forth in the notice.

CHAIRMAN LA ROSA: Thank you, Chairman.

COMMISSIONER GRAHAM: Mr. Chairman.

CHAIRMAN LA ROSA: All right. Let's go ahead and take appearances, starting with Duke.

MS. TRIPLETT: Good morning, Commissioners. Dianne Triplett for Duke Energy Florida. And I would also enter an appearance for Matt Bernier and Stephanie Cuello.

CHAIRMAN LA ROSA: Office of Public Counsel.

MR. REHWINKEL: Good morning, Mr. Chairman and Commissioners. My name is Charles Rehwinkel, appearing on behalf of the Office of Public

Counsel. I would also like to enter an appearance for Walt Trierweiler, the Public Counsel, Ali Wessling, Austin Watrous, Patty Christensen and Octavio Ponce.

CHAIRMAN LA ROSA: Thank you.

Americans for Affordable Clean Energy, also Circle K Stores, RaceTrac and Wawa, which we will refer to as the fuel retailers.

MR. ASCHAUER: Good morning, Mr. Chairman. Yes, my name is Fred Aschauer of Lewis, Longman & Walker, and I am here on behalf of what have collectively been called the fuel retailers.

CHAIRMAN LA ROSA: Thank you. I appreciate clarifying that. We are also not all sitting in order, if that hasn't been addressed. I am sorry if I am looking around.

EVgo Services.

MR. STILLER: Mr. Chairman, counsel for EVgo was excused from the final hearing.

CHAIRMAN LA ROSA: That's correct. Thank you.

FIPUG.

MS. MOYLE: Serena Moyle on behalf of the Moyle Law Firm. I would like to make an appearance also for Jon Moyle and Karen Putnal.

CHAIRMAN LA ROSA: Thank you.

Florida Retail Federation.

MR. WRIGHT: Thank you, Commissioner, Mr. Chairman. Robert Scheffel Wright, the Gardner Bist Law Firm appearing on behalf of the Florida Retail Federation. I would like to also enter an appearance for my law partner, John T. Lavia, III.

Thank you.

CHAIRMAN LA ROSA: Thank you.

LULAC.

MR. MARSHALL: Bradley Marshall on behalf of Florida Rising and the League of United Latin American Citizens of Florida, better known as LULAC. I would also like to enter an appearance for Jordan Luebkemann and Hema Lochan.

Thank you.

CHAIRMAN LA ROSA: Thank you.

Nucor Steel.

MR. BRISCAR: Good morning, Mr. Chairman. Joseph Briscar, appearing on behalf of Nucor Steel Florida. I would like to also enter an appearance for Pete Mattheis and Michael Lavanga.

Thank you.

CHAIRMAN LA ROSA: Thank you.

PCS Phosphate, White Springs.

MR. BREW: Good morning, Chairman,

Commissioners. For white Springs Agricultural Chemicals, PCS Phosphate, I'm James Brew. I would like to note an appearance of Laura Wynn Baker and Sarah Newman.

CHAIRMAN LA ROSA: Thank you.

Sierra Club.

MR. GARNER: Hi, William Garner, appearing on behalf of the Sierra Club. I am also appearing on behalf of the Southern Alliance for Clean Energy.

CHAIRMAN LA ROSA: Thank you.

Walmart.

MS. EATON: Good morning, Chairman. Stephanie Eaton of the law firm of Spilman, Thomas & Battle. And I would also like to enter an appearance for Steven Lee, both on behalf of Walmart, Inc.

Thank you.

CHAIRMAN LA ROSA: Thank you.

Commission staff.

MR. STILLER: Shaw Stiller for Commission staff. I would like to also enter an appearance for Major Thompson and Jennifer Crawford.

MS. HELTON: And Mary Anne Helton is here as your Advisor, along with your General Counsel, Keith Hetrick.

CHAIRMAN LA ROSA: Great. Thank you.

Staff, are there any preliminary matters that need to be addressed?

MR. STILLER: Staff is unaware of any preliminary matters.

CHAIRMAN LA ROSA: Do any of the parties have any preliminary matters that we need to address? Okay. Seeing none.

Okay. We will then move to opening by the parties. As set forth in the Prehearing Order, we are going to first hear opening statements from the parties who signed the proposed Settlement. After all signatories who wish to make opening statements have done so, I will go down the list of Intervenors who did not sign the 2024 Settlement Agreement, and give each of you a chance to briefly state your position for the record. Any party may, of course, waive their opening if so desired.

We will start, of course, here at the beginning with Duke. We'll hear from, again, the signatories. Please keep in mind, let's -- let's try to keep the openings to five minutes. I won't go crazy if we go a little bit over that. That's okay.

And let's start with Duke. Ms. Triplett, you are recognized.

MS. TRIPLETT: Thank you, Mr. Chair. And good morning again.

Duke Energy Florida is pleased to be here today with an unopposed settlement agreement. If you had told me just a few months ago that we would be here in this posture, I would not have agreed -- I would not have believed it. I have now been doing this for 20 years, and I can say that this was the hardest negotiation that I have ever done. But as Tom Hanks in A League of Their Own said, the hard is what makes it great.

And the 2024 Settlement Agreement is great. It is in the public interest. It results in fair, just and reasonable rates. It reflects collaborations from varied parties' interests, and there is a lot of here. And we ask that the Commission approve in its entirety without modification.

And for making this outcome possible, we would like to thank the leadership, experts, lawyers and support staff of all the parties who spent many hours to achieve a reasonable compromise.

I also want to thank your staff, who has done an expansive and in-depth review of the company's petition, testimony and exhibits, as well as the underlying data supporting it.

We answered over 3,000 interrogatories and request for productions in this case. We produced more than 75,000 pages of documents, and that's only counting Excel files as one page, the Bates label. And we filed 40 sets of direct and rebuttal testimony and exhibits. And that's in support of our litigated case, and ultimately our settled -- our settled case.

So given the robust litigation activity in this case, the company believes it's significant when the utility, OPC and all of these parties are able to find common ground and resolve or limit disputes before the Commission.

The Settlement fairly provides for the investments the company must make to serve customers while minimizing impacts to customer bills.

The 2024 -- 2024 Settlement Agreement has many components, but I wanted to highlight a few key provisions that demonstrate the public interest.

First, by utilizing a creative monetization of investment tax credits in 2027, we are able to stay out of a base rate proceeding for three years and reduce bill impacts for customers. Over the three-year period, the 2024 Settlement Agreement reduced the total base rate revenue requirements from $736 million in DEF's adjusted litigated request to approximately $330 million, a 55-percent decrease.

Based on what we know now, if you approve this agreement, we still expect January 2025 bills to be lower than December 2024 bills.

What will the settlement allow the company to do? Continue investing in the grid to serve increased population growth and improve reliability; make ongoing power plant enhancements and efficiencies to generate fuel savings for customers; build 900 megawatts of new solar energy and utility battery -- utility scaled battery storage.

We have a panel of witnesses available to answer additional questions you may have regarding the settlement, but now I want to turn it over to our state President, Melissa Seixas, and the good news she is not a lawyer, so you get a break from the lawyers.

MS. SEIXAS: Good morning, Commissioners. Thank you for allowing me the opportunity to say a few words this morning.

I have had the honor of working for Duke Energy Florida for nearly 40 years. And much of that time, nearly all of that time, has been in some role that is customer facing. And so dealing directly with our customers is something of primary responsibility to our employees, and we take that very seriously. It's a privilege to serve our communities and our customers, and they trust us to provide reliable power.

When I first stepped into the role of state president about three-and-a-half years ago, we had just executed the 2021 Settlement Agreement, and I had been able to see firsthand how diligently our company works on making these investments and executing projects on -- for the benefit of our customers. And now, of course, I have seen the effort that goes into preparing a rate case, and I have an even more deep -- deeply new founded respect for the entire process.

The negotiations were absolutely tough, but they have resulted in a settlement that fairly balances all interests. With this settlement, we will continue to do the important work towards a cleaner energy future, while prioritizing reliability and price stabilization. And our customers are already benefiting from these investments that we are making.

As you know, Hurricane Debby made landfall only a couple weeks ago. Duke Energy was able to rapidly restore 90 percent of service back to customers who were impacted by the storm within 24 hours. And with the investments we've made, we saw 12-and-a-half million customer outage minutes avoided because of technology installed on our system. We credit the rapid response to our year-round storm preparations and grid hardening, innovative technology, decades of lessons learned, and key collaborations with state, local and community response agencies.

I wanted to take a few moments just to highlight some of the provisions in the settlement that are particularly focused on our most vulnerable customers.

Specifically, Duke Energy will suspend disconnects for nonpayment of Duke Energy Florida bills when actual temperatures reach 95 degrees or greater. And during the term of the settlement, we will also waive reconnection fees for all customers, including those who have been disconnected for nonpayment.

And finally, we will increase participation in our Neighborhood Energy Safer Program by 10 percent, and increase the installation of smart thermostats from 10 percent to 40 percent for income qualified customers.

Before I close, I want to extend my appreciation on behalf of the 3,800 employees here in Florida, that appreciation for the Office of Public Counsel, all of the parties that have participated in the settlement agreement and, of course, to Commission staff.

We ask that you approve the settlement for the continued benefit of our customers.

Thank you.

CHAIRMAN LA ROSA: Thank you.

OPC.

MR. REHWINKEL: Good morning again, Commissioners. Charles Rehwinkel on behalf of the office.

Commissioners, on behalf of, and along with, the Public Counsel, Walt Trierweiler, my colleagues, Ali Wessling, Auston Watrous, Patty Christensen, Octavio Ponce and I are appearing in strong support of the agreement before you, together with OPC professional staff accountants, Marshall Willis, Bart Fletcher, Jena Price and Sarah Lewis, and the six outside experts we engaged on this epic and unprecedented case, we ask you together to approve the Settlement Agreement.

It would be easy, Commissioners, to just advocate that. Consistent with his duties and powers asset out in Section 350.0611(2), the Public Counsel supports this agreement taken as a whole, and that he urges you to approve it since he deems it to be in the public interest.

I could just stop there and ask you to consider only that and Mr. Trierweiler's signature in your deliberations, but I will not. There is an extensive and robust basis for you to approve the agreement, and I would like to highlight a few of these reasons while providing you with some of the back story of why this agreement is so completely immersed in the public interest.

The Public Counsel engaged six experts in accounting, depreciation, finance, forecasting, engineering and resource planning, along with our internal accounting and regulatory experts, to fully analyze this case. We conducted months of intense discovery. We sent Duke 736 interrogatories, 212 document requests, those yielding over 55,000 pages of discovery responses, and we conducted eight lengthy depositions.

As you have heard today, all the intervenors and staff together served 2,374 interrogatories and 694 document requests, yielding over 75,000 pages of discovery responses.

The OPC alone filed six sets of expert witness testimonies. Other intervenors filed expert testimony as well; while, as you have heard, the company filed the direct and rebuttal testimony of their 21 expert witnesses for 40 testimonies in all.

By statute and by agreement, and by the rules of the Bar, the parties are prohibited from discussing the details of the process that led to settlement, but I can say that it was an arduous process. Negotiations spanned many months, impasses were reached on multiple occasions. The breadth and variety of the parties who were engaged in negotiations, both from the start and collected along the way, were unprecedented.

Perhaps the number and variety of parties engaged in the process -- made the process more difficult, but it is undeniable that it also made the resulting agreement better, more sound and more credible overall.

What matters is not how the negotiations went. What matters is the result. The Public Counsel strongly submits that this result was well-grounded, broadly based and in the public interest.

You will hear testimony today from DEF witness Olivier and others that fairly present some of the key settlement provisions, but keep in mind, though, that the entire document speaks for itself. Perhaps the most significant elements from the Public Counsel's standpoint are the relatively modest levels of rate increases for 2025 and 2026, along with the fact of no rate increase in 2027.

Additionally, the separated recovery for the solar plants on an à la carte basis was a very significant balanced benefit for all concerned. When contrasted with the cases filed, these outcomes clearly resulted in fair, just and reasonable rates that are in the public interest.

Commissioners, it cannot be stated enough. You have before you an uncontested global settlement of what, when it began, when filed -- no, actually, even before it was filed -- as a highly controversial and, at times, bitterly contested and unprecedented three-test-year rate case, that this case was settled in the comprehensive way that it was is a remarkable result, and it should be factored into your public interest consideration and determination.

The Prehearing Order 24-0360, at pages two and three, indicates that there are 12 parties providing basic positions for this hearing. Among these 12 parties are zero objections or oppositions. 12 and 0, that's a pretty good football regular season record, but it is an even better statistic for a two-million customer electric utility rate case settlement.

Let's break that number down. You have six signatories, DEF; the Public Counsel on behalf of all customers; FIPUG, representing the industrials; Florida Retail Federation, representing large, medium and small retailers; PCS Phosphate, perhaps DEF's largest customer; and Nucor Steel, perhaps DEF's newest large customer. Each is affirmatively asking for your approval of the agreement.

You have five parties expressly stating that they have no objection to you approving the agreement. LULAC and Florida Rising together -- maybe it's six parties -- SACE, Sierra Club, EVgo and Walmart. And you have one party taking no position, the Fuel Retailers. Again, 12 parties, no opposition.

The Public Counsel believes that the Commission can look at the broad cross-section of customer representatives and diverse interests represented among them and soundly reach the conclusion that the overall result of this global agreement, taken as a whole, is squarely in the public interest.

I could stop there, but the Public Counsel asked you to look deeper because there is more. This agreement strikes a good balance among all the interests affected. There are both customer and shareholder benefits that strike an appropriate balance between Duke and its customers, while also providing balance among the varied customer interests.

While these elements are, indeed, born of compromise, they are more than just some rote meeting in the middle. Instead, they represent a genuine in-depth reasoned effort among the varied interests to develop a fair outcome on revenue requirements and revenue allocations, and other elements impacting the changing utility landscape.

The agreement, when taken as a whole, results in fair, just and reasonable rates. It resolves the issues in this case -- that this case placed before you, and is clearly in the public interest. I would like to discuss a few of the provisions for your further consideration, though.

Notably, the agreement has a three-year stay-out and a base rate freeze, and it continues many of the negotiated terms that have been fundamental to previous Duke agreements. Even though many of them have been here before, each was still bargained for and renewed as the product of concession, and each is the product of reasonable compromise and outcome.

These provisions are not boilerplate. Many of them have been in place for years, and have quietly generated seen and unseen material benefits to all parties in the form of predictability, efficiencies and shared customer and shareholder benefits. Every provision of this agreement was intentionally and thoroughly negotiated, and has meaning to some or all of the parties here today and to the public in general. This in this respect, they contribute to the fairness and reasonableness of the result goes rates and to the agreement being in the public interest.

Finally, I would like to single out two provisions for illustration.

First, the negotiated and bargained for tax provision in paragraph 19 is continued in this agreement. It was first implemented in 2017, and has generated hundreds of millions of dollars of revenue requirement savings to customers, as well as providing certainty and predictability to the company in terms of the pace of flowback of deferred taxes, for example. This provision worked in both directions, and it will be in place for the next three years to provide that balance as needed.

Second, paragraph 24C, the storm cost recovery mechanism, or SCRM, provision has been a part of the bargained for negotiated provisions with Duke since 2010. It has unfortunately been invoked several times since 2017 in the case of Hurricane Irma, when it was coupled with the tax provision to pay for storm damage with minimal bill impacts. In 2018, Michael again triggered its. Use, more recently, Hurricanes Ian, Isaias, and Idalia have caused its invocation. In each case, the SCRM was used to provide certainty for the storm level for damage cost recovery, and for financing needs of the company. This is a balanced outcome that serves the public interest and the state as a whole.

Additionally, pursuant to the stipulation that followed the Irma experience, this process has been audited as a result of the Ian, Isaias and the Idalia storms. And the Public Counsel believes it is working as originally intended to balance the interest of customers and the company to provide timely and accurate cost recovery in a streamlined fashion.

I mention these two provisions because they illustrate the depth of the settlement agreement. It is more than just a revenue requirement and ROE vehicle. The agreement contains many terms resulting from the give and take of negotiation that have been time-tested and functioned as intended. They continue as part of the overall agreement and exist along with the marquee terms that get the most attention, ROE, rate levels and bill impacts.

My point here is that all of the terms in the agreement work together to provide substance and meaning and fairness and reasonableness in the rates overall and the result in the public interest test being satisfied -- they result in that being satisfied.

I want to close with this and bring it around to the bottom line for customers.

As you have seen in the agreement, what I have dubbed marquee terms are at levels that are materially less than those which customers faced back in early April. The litigation process overseen by you and your staff, combined with the negotiations among the parties, have resulted in a very reasonable outcome that the Public Counsel has determined appropriately factors in the risks that we faced at hearing. And in this regard, he urges your approval of the settlement as being in the public interest and resulting in fair, just and reasonable rates.

I want to thank your staff and all the other parties for making it possible for us to be at this point today, and we sincerely ask for your approval.

Thank you.

CHAIRMAN LA ROSA: Thank you.

FIPUG.

MS. MOYLE: Serena Moyle for FIPUG.

FIPUG supports the settlement agreement and believes that it is in the public interest. FIPUG would like to thank the negotiating parties for working hard and reaching an agreement. FIPUG also thanks the staff and Commission do promptly considering the settlement agreement and putting the litigation on hold.

Thank you.

CHAIRMAN LA ROSA: Thank you.

White Springs, PCS Phosphate.

MR. BREW: Yes. Thank you. James Brew.

PCS Phosphate strongly supports the Settlement Agreement and maintains that it is definitely in the public interest.

Just to expand a little bit. It is in the nature of effective settlements for the parties to engage, discuss and compromise. And that, as Mr. Rehwinkel said, was particularly arduous here.

The one thing I want to point to is that none of the parties that dug into the rate filing, conducted discovery, filed testimony and engaged in the settlement discussions are opposed. That is testament to the really hard fought balance that this settlement agreement provides.

Thank you.

CHAIRMAN LA ROSA: Thank you.

Nucor.

MR. BRISCAR: Good morning, Commissioners, Mr. Chairman. Thank you for your time and attention today.

Nucor Steel Florida is a signatory to the settlement agreement in this case, and we strongly support it. We respectfully urge the Commission approve the settlement agreement.

Nucor is one of Duke's newest industrial customers having located in Florida just a few years ago. Affordable electricity rates are vitally important to industrial customers, especially those in globally competitive markets like Nucor.

In our view, the Settlement Agreement represents a reasonable compromise of competing positions and it is in the public interest. The parties worked hard to reach resolution in this case, and the Settlement Agreement is a testament to that hard work. To of that end, I want to thank OPC and Duke and all the parties for their efforts. Each party diligently presented their positions, but we all worked together to reach a settlement.

I also want to thank staff for their efforts in reviewing the settlement. And in short, we support the Settlement Agreement, and respectfully ask that the Commission approve it as presented.

Thank you.

CHAIRMAN LA ROSA: Thank you.

Florida Retail Federation.

MR. WRIGHT: Thank you, Mr. Chairman, and Commissioners. Good morning on behalf of the Florida Retail Federation. I will start by saying we strongly support the settlement and urge you to approve it. I have these brief comments.

As with most settlements, there was a lot of give and take, and there were many compromises that all parties worked toward and worked with to get us here. The Retail Federation is particularly grateful to the Duke team, to the Office of Public Counsel, their entire internal staff team and their team of six experts who worked tirelessly to make this happen. We are also grateful to all of the other parties who had some competing interests that we had to work through to get us here today.

We are specifically and profoundly grateful to your staff and to you for getting this handled as quickly and professionally as you have, as you always do.

The FRF strongly supports this settlement and respectfully asks that you approve it -- approve this unopposed settlement in the public interest.

Thank you very much.

CHAIRMAN LA ROSA: Thank you for those openings.

I will now give each of the non-signatory Intervenors the opportunity to state their position for the record. Each of you has set forth your respective positions in the joint motion to approve the 2024 Settlement, so you may simply adopt that as your position here today, if you so wish. If you can -- if you choose to make a statement, please do so in a respectable timeframe to keep us rolling here today.

I will start with the first here as Florida Rising and LULAC.

MR. MARSHALL: Thank you, Mr. Chairman. Bradley Marshall on behalf of Florida Rising and LULAC, and I will be brief.

Although we did not sign the Settlement Agreement, we are proud to be supportive of the settlement and to not oppose it. There is a lot to like about the Settlement Agreement, and we celebrate the collaborative efforts of the parties to reach a settlement that everyone, including

Florida Rising and LULAC, can live with. We believe the settlement is a fair compromise between the parties and results, for the first time in recent memory, moving residential customers closer to parity under Duke's 12 CP and 25 percent AD cost of service by giving residential customers a lower increase than the other customer classes. That's the right thing to do, and we are glad all of the parties either agreed or did not object to doing that here.

As a result of this agreement, as you heard, and as you saw in the FEECA dockets, Duke has also agreed to increase the size of its low-income energy efficiency program, and increase its residential energy efficiency goals, the cheapest and easiest way to lower electricity bills in this state, and try to make electric bills more affordable.

As a result of this agreement, as you remembered, Duke agreed to implement a better heat disconnection policy, ensuring that customers won't be cut off from life-saving air conditioning days where it's going to be 95 degrees or above, or the heat index 105 degrees and above. As a result of this agreement, Duke agreed to waive reconnection fees after folks are disconnected for nonpayment, making it easier for people to get their electricity reconnected if they fall behind on their bills. This happens all too often for struggling hard-working families in the state. And Duke has also agreed to waive their $30 minimum bill for low-income customers.

Thank you for the opportunity to address you today, and thank you to all of the parties for making this agreement possible.

Thank you.

CHAIRMAN LA ROSA: Thank you.

Sierra Club.

MR. GARNER: Thank you, Mr. Chairman. The Sierra Club, and I am going to go ahead and speak for SACE while I am here since I represent them too. Both organizations join in the sentiments expressed by Mr. Marshall, and we will waive the balance of our time.

CHAIRMAN LA ROSA: Thank you. A lot of transition to happen. The Fuel Retailers, you are recognized when you are ready.

MR. ASCHAUER: I had a feeling I would be next.

Thank you, Mr. Chair, Commissioners Passidomo, Fay, Graham and Clark. The Fuel Retailers own and operate 307 stores within the Duke service territory, with plans to expand both their footprint and the services that they offer their customers, including the development of additional electric vehicle charging stations.

The Fuel Retailers are significant customers of Duke Energy, relying on its electricity to fuel their existing operations and to support their ongoing investments in EV charging infrastructure.

As Floridians continue to transition from internal combustion engines to EVs, it's imperative that there is a robust, affordable and competitive EV charging infrastructure in place to support them. Encouraging private investment in this sector will enhance Floridians' daily travel, accommodate the millions of tourists who visit our state each year, and ensure safe and effective evacuations during emergencies. The Fuel Retailers have the footprint infrastructure and the experience to develop a robust network of EV chargers. We believe the proposed Settlement Agreement is a step in that direction.

Capital costs can present a significant barrier to private investment. The Electrical

Vehicle Make-Ready Infrastructure Program will help offset some of those expenses.

Furthermore, the tiered per segment rebate approach, including the custom incentive for public chargers over 50 kilowatts will encourage development. Beyond infrastructure costs, the rates for electricity used in EV chargers are also crucial.

So after a thorough review, I can represent that the Fuel Retailers support the Settlement Agreement as it relates to the EV Make-Ready Infrastructure Program. Indeed, as interested parties, the Fuel Retailers look forward to collaborating with Duke Energy to develop a pilot rate as outlined in the draft Settlement Agreement before you today for your consideration.

So with that, Mr. Chair, I thank the parties for their time and efforts in this, and I thank you and your staff for the time and consideration today.

CHAIRMAN LA ROSA: Thank you.

EVgo has been excused from today, so let's move to Walmart.

MS. EATON: Good morning. Stephanie Eaton again for Walmart, Inc.

Walmart is a large commercial customer of Duke Energy Florida, owning and operating approximately 70 retail stores, a distribution center and related facility in the company's territory. Collectively, these facilities consume over 200 million kilowatt hours of electricity annually from the company. The cost of electric utility service is a significant element in the cost of operation for Walmart at these multiple locations throughout the state.

Walmart participated in DEF's rate case both individually and through its membership in the Florida Retail Federation, pursuant to which Walmart's Senior Directer of Utility Partnerships Steve Chriss filed testimony and exhibits that were stipulated into the record.

Walmart agrees that -- with OPC, that while the statute, by rule, negotiating the parties confidential agreement prohibits discussion of the settlement process, Walmart can state that it was a participant in the many months of hard fought -- hard fought negotiations among the numerous parties, each of which had varying issues of import with regard to DEF's filed rate case.

While not a signatory as an individual DEF customer, Walmart affirms to this commission that it had every effort to thoroughly review the Settlement Agreement, and does not oppose the Commission's approval of the 2024 Settlement Agreement as filed.

Provisions of importance to Walmart include the substantial reduction in the agreed upon rate increases for DEF customers compared to DEF's filed case; the three-year stay-out that provides the stability and predictability of rates for all DEF customers; the resolution of the interruptible and standby credits in paragraph eight of the 2024 Settlement Agreement, which also led to the resolution of issues the parties had with DEF's position in its recent FEECA goals docket, Docket No. 20230013-EG.

Further, Walmart supports DEF's commitment to and settling parties agreement to DEF's plans to construct 12 additional solar facilities within the parameters set forth in paragraph 16 of the 2024 Settlement Agreement. An increase in the renewable generation is consistent with Walmart's extensive and ambitious sustainability and renewable energy goals.

Moreover, Walmart supports DEF's agreement in paragraph 37 of the 2024 Settlement Agreement to conduct a study to analyze the contribution of solar facilities to winter and summer capacity. This information will better inform DEF and its customers of solar capacity values for the facilities constructed pursuant to paragraph 16 of the 2024 Settlement Agreement.

In addition, DE -- Walmart supports DEF's option to file for separate Commission approval of an optional pilot rate suitable for EV DCFC customers, and agreement to work with those interested parties to develop the proposed pilot rate as set forth in paragraph 18F of the 2024 Settlement Agreement. As Walmart has EV chargings stations for its own customers, and it's own commercial fleet vehicles, that will need DCFC charging stations in the coming years, Walmart will be happy to work with DEF on an EV DCFC pilot.

To conclude, Walmart appreciates the exhaustive efforts that DEF and its team made during settlement negotiations and to present the 2024 Settlement Agreement to the Commission, OPC and the excellent analysis and insight of its team and expert, collaboration with all of its fellow intervenors and with staff to achieve a settlement agreement that is uncontested by any party in this docket.

Thank you.

CHAIRMAN LA ROSA: Thank you, and thank you to all for your opening statements.

Let's move to the record, staff.

MR. STILLER: Yes, Mr. Chair.

Staff has prepared a Comprehensive Exhibit List, which includes the prefiled exhibits attached to each witnesses' prefiled testimony, exhibits identified by staff and two exhibits from the service hearings. The list has been provided to the parties, Commissioners and the court reporter.

Staff requests that the list itself be marked as Exhibit No. 1 at this time, with all subsequent exhibits marked as indicated on the list.

CHAIRMAN LA ROSA: Thank you. We will mark the list as Exhibit 1, then the others will be Exhibit 2 through 274?

MR. STILLER: That's correct.

(Whereupon, Exhibit No. 1-274 were marked for identification.)

MR. STILLER: And it is staff's understanding that the parties do not object and stipulate to the admission of CEL, which is marked as Exhibit No. 1.

The staff requests that Exhibit No. 1 be admitted at this time.

CHAIRMAN LA ROSA: Seeing no objection -- objections, Exhibit 1 is admitted.

(Whereupon, Exhibit No. 1 was received into evidence.)

MR. STILLER: Thank you, Mr. Chair.

It's staff's understanding that the parties do not object and stipulate to the admission of the remaining exhibits, No. 2 through 274. These exhibits include the prefiled exhibits attached to each witnesses' testimony, exhibits identified by staff, and two exhibits from the service hearings. And staff requests that Exhibits 2 through 274 be admitted at this time.

CHAIRMAN LA ROSA: Seeing no objections, see that 2 through 274 are admitted.

(Whereupon, Exhibit Nos. 2-274 were received into evidence.)

MR. STILLER: It is staff's understanding that the parties also do not object to and stipulate to the admission of the prefiled testimony of the witnesses in this case. Staff requests that the witness testimony be entered into the record as though read in the following order:

Prefiled direct from DEF: Melissa Seixas, Ned Allis, Reginald Anderson, Nicole Aquilina, Benjamin Borsch, Rebekah Buck, Shannon Caldwell, Matthew Chatelain, Timothy Duff, Vanessa Goff, Hans Jacob, Jeffrey Kopp, Brian Lloyd, James McClay, Adrian McKenzie, Karl Newlin, Michael O'Hara, Marcia Olivier, John Panizza, Lesley Quick and Edward Scott.

Staff notes that the direct testimony of witness Shannon Caldwell has been adopted by DEF witness Misty Easton.

OPC prefiled direct witnesses: James Dauphinais, David Dismukes, William Dunkel, Daniel Lawton, Kevin J. Mara and Helmuth Schultz.

For the Fuel Retailers, David Failkov.

For EVgo, witness Lindsey Stegall.

For FIPUG, Jonathan Ly and Jeff Pollock.

For FRF, Steve Chriss.

For LULAC and Florida Rising, MacKenzie Marcelin and Karl Rabago.

Nucor/PCS Phosphate, Tony Georgis.

Sierra Club, Rose Anderson.

And finally for Commission staff, Angela Calhoun and Simon Ojada.

It is also staff's understanding that the parties do not object to the admission of Duke Energy Florida's prefiled rebuttal testimony. The staff requests that the following witnesses' testimony be read into the record in the following order as though read: Ned Allis, Reginald Anderson, Benjamin Borsch, Matthew Chatelain, Timothy Duff, Misty Easton, Vanessa Goff, Timothy Hill, Jeffrey Kopp, Brian Lloyd, Adrian McKenzie, Sharif Mitchell, Karl Newlin, Michael O'Hara, Marcia Olivier, John Panizza, Lesley Quick, Edward Scott and Paige Swafford.

Those are all the witnesses with prefiled testimony, Mr. Chairman.

CHAIRMAN LA ROSA: Thank you.

Seeing no objections, the prefiled testimony for all the witnesses is admitted and moved into the record as though read.

(Whereupon, prefiled direct testimony of Melissa Seixas was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC

Docket No. 20240025-EI
Submitted for filing: April 2, 2024

DIRECT TESTIMONY
OF
MELISSA SEIXAS

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Melissa Seixas. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company"), as the State President.

Q. What are your responsibilities in that position?

A. I lead the regulated electric utility business in Florida, which serves nearly 2 million electric customers. I am responsible for the Company's financial performance, as well as managing regulatory affairs, rates and regulatory filings, state and local government affairs, and community relations.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor's Degree in American History from Eckerd College and a Master's Degree in American History from the University of South Florida. My executive training includes a Corporate Social Responsibility ("CSR") certification from Johns Hopkins University, and programs with the Edison Electric Institute and Georgetown University's McDonough School of Business. I have over 35 years of utility experience, primarily in government and community relations. I began my career in 1986 with Florida Power Corporation (later to become Progress Energy and then Duke Energy) as a draftsman for the then-distribution (now customer delivery) department. Since, I have served in numerous

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customers facing/supporting roles with increasing leadership responsibilities. Prior to assuming my current position in February 2021, I served as the Vice President of Government and Community Relations in Florida. I directed efforts to strengthen relationships with local municipal, community, and civic organizations, as well as business leaders throughout the company's 35-county service area.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss DEF's need for a base rate increase. Our customers benefit from the investments DEF has made over the last several decades and are receiving more reliable, resilient, and cleaner power than ever before. DEF is committed to maintaining this trajectory in the most cost-efficient manner possible by continuing to: (1) add solar generation and energy storage capacity; (2) make the energy grid even more reliable and resilient; and (3) improve the efficiency and flexibility of existing generating plants to help lower fuel costs while proactively managing the changing grid. Despite DEF's efforts to minimize costs, DEF must request a rate increase from the Florida Public Service Commission ("Commission"). DEF understands the impact that requesting a base rate increase has on our customers and it is not something that the Company takes lightly, as we know customers trust us to manage our costs and spend what is necessary to provide the safe and reliable service they depend on. However, to maintain this level of service, DEF must request an increase.

Q. Do you have any exhibits to your testimony or sponsor any Minimum Filing Requirements ("MFRs") in this proceeding?

A. I do not have any exhibits, but I do sponsor MFR F-9: Public Notice. This MFR is true and accurate, subject to being updated throughout the course of this proceeding.

Q. Would you please summarize your testimony?

A. Yes. The Company is requesting additional revenue to continue customer-centric investments that provide customer savings and deliver reliable clean energy as well as expanded options that enhance the customer experience. This is all made possible by our approximately 3,700 dedicated and engaged employees who live and/or work in the communities we serve.

In my direct testimony I provide: (1) an overview of our customer driven focus on operational excellence, cost control, clean energy transformation, and enhancing the customer experience; (2) a description of DEF's 2021 Settlement Agreement[1] and how that agreement benefitted our customers; and (3) a summary of DEF's rate case filing, including an introduction of the other witnesses and key topics they cover in their direct testimony.

II. <u>DEF DESCRIPTION AND CORE VALUES</u>

Q. Please describe DEF.

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[1] Approved in Order No. PSC-2021-0202-AS-EI

A. DEF is a wholly owned subsidiary of Duke Energy Corporation. DEF has been powering the lives of Florida customers (though its predecessor companies St. Petersburg Electric Light & Power Company, Florida Power Corporation, and Progress Energy Florida) since 1899. DEF provides retail electric service to nearly 2 million customers across 35 counties in Florida. DEF is subject to regulation by this Commission and the Federal Energy Regulatory Commission.

The Company operates 68 generating units, including nine combined cycle power blocks, two coal-fired steam units, two gas-fired steam units, one cogeneration facility, 34 simple cycle combustion turbines ("CTs") and 20 regulated solar sites. Mr. Reginald D. Anderson describes these assets in more detail in his testimony. DEF's transmission system, as described by Mr. Edward L. Scott in his testimony, consists of approximately 5,300 circuit miles of transmission lines, including 500 kV, 230 kV, 115 kV and 69 kV lines, transmission substations, towers, poles and related equipment and material. DEF also owns, maintains, and operates approximately 18,000 circuit miles of overhead primary voltage distribution conductors, approximately 16,000 miles of underground primary voltage distribution cable, distribution substations, and related poles, transformers, secondary cables, secondary wires, and other materials and equipment, such as bucket trucks, to provide reliable service as explained by Mr. Brian Lloyd in his testimony.

Q. What are DEF's core values?

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A. At DEF we are consistently focused on: (1) Operational Excellence; (2) Enhancing our Customers' Experience; and (3) Employee & Stakeholder engagement. These core values help us power the lives of our customers and the vitality of our communities. At the very foundation of our Company is a commitment to deliver reliable energy to our customers and communities. It is a tremendous privilege to be trusted with providing this essential service and we are committed to providing our customers with reliable, cost efficient, and increasingly clean energy. DEF continues to improve the reliability and resiliency of the grid in the face of more frequent extreme weather events while at the same time evaluating and implementing ways to stabilize our customers' costs.

Q. Has Duke Energy received any awards?

A. Yes. Duke Energy is the proud recipient of many awards, which further demonstrate our commitment to each of our core values. The awards range from focus on employees to sustainability and storm response. A non-exhaustive list is included below:

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#	Description	#	Description
1	America's Best Employers by Forbes.	10	National Society of Black Engineers (NSBE) SEEK Award.
2	America's Best Employers for Women by Forbes.	11	No. 1 among U.S. utilities for investor transparency by Labrador Advisory Services.
3	America's Most JUST Companies in 2024 by JUST Capital (ranking 57th overall)	12	SAP Industry Innovation Award.
4	Best Companies for Diversity by Black Enterprise.	13	Top 10 Utilities in Economic Development from Site Selection Magazine's Annual List.
5	Best Employers for Diversity by Forbes.	14	Top 300 Most Responsible American Companies by Newsweek.
6	Best Places to Work for LGBTQ Equality by the Human Rights Campaign.	15	Top 50 Employers by CAREERS & the disABLED Magazine.
7	Emergency Recovery Award by Edison Electric Institute.	16	Top Employer for Female Engineers by Woman Engineer Magazine.
8	Employer Support Freedom Award by the U.S. Secretary of Defense.	17	World's Most Admired Companies by Fortune.
9	Named to the Dow Jones Sustainability Index multiple years in a row.		

III. <u>OPERATIONAL EXCELLENCE AND CUSTOMER SERVICE</u>

Q. What is Operational Excellence?

A. Operational Excellence cuts across multiple business units and functions. At every step of generating, transmitting, and distributing energy, DEF has a relentless commitment to performing tasks safely, reliably, and efficiently. Operational Excellence empowers us to exceed customer and stakeholder expectations by operating safely, reliably, and cost efficiently. Operational Excellence establishes operational discipline through organizational alignment, and behaviors.

Q. Please provide some examples of how DEF's Regulated & Renewable Energy (RRE) group meets the Operational Excellence core value.

A. DEF's generation fleet has undergone a significant transformation over the last five years as it has evolved into a cleaner, more efficient, and more capable fleet.

Since 2018 the generation fleet heat rate, which measures the unit efficiency, has improved as we retired some higher heat rate coal units, improved the efficiency of our gas units, and incorporated new solar generation. The RRE team has also been able to maintain or even reduce operating expense associated with the day-to-day operations of the fleet even as new generation has been added. This transformation is explained in Mr. Reginald Anderson's testimony.

Q. How have the Customer Delivery and Transmission teams demonstrated Operational Excellence?

A. As detailed in Mr. Brian Lloyd's and Mr. Edward Scott's testimonies, DEF utilizes reliability data to assess and track the performance of our distribution and transmission systems using generally accepted reliability measures or indices in the electric utility industry. One of the main metrics utilized for both distribution and transmission is System Average Interruption Duration Index ("SAIDI"), which reflects the average number of minutes each customer was without power during a given period. Over the 6-year period from 2018-2023, DEF distribution SAIDI has improved 27 percent. The Transmission Grid has also shown significant improvement with Transmission Grid SAIDI decreasing by 50% and Outages per Hundred Miles per Year – Sustained Automatic ("OHMY-SA") improving by 14% since 2018.

Q. Please discuss DEF's storm response efforts.

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A. DEF continuously prepares for storms throughout the year. Our team conducts annual exercises to prepare for major weather events that have the potential to disrupt electric service to customers in Florida. The drills are intended to assess the preparedness of the Transmission and Customer Delivery teams to respond to major weather events as well as the effectiveness of the response plans. Identification of knowledge, tool, and/or process gaps to be addressed prior to the start of each hurricane season is a key outcome of the exercises.

DEF works with state and local emergency operations centers ("EOCs") and elected officials year-round to ensure our communities are prepared and we are prepared to meet those stakeholders' needs and expectations. Prior to storm season commencing, we meet with the county EOCs to ensure they are aware of any changes we may have made to our storm responses processes. These meetings also provide an opportunity for our Community Relations Managers and EOC representatives to be abreast of any change in county staff.

During emergencies, our customers count on us the most. Public safety and critical infrastructure are our top priorities during any restoration. Every employee has a responsibility to respond when called. We use several different communication mediums to relay information to our customers prior to, during, and after a storm. These include press releases, social media, and direct customer communication. We believe it is important for our customers to have the most accurate and up to date outage and restoration information. Throughout a storm, our team provides support and information to our EOCs, state and local elected officials, key stakeholders, and all customers. As we have experienced in prior storms, the

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constant flow of communication out of the county EOCs, into our Storm Rooms is key to having successful restoration activities.

Our grid strengthening work continues to improve reliability for our customers, enhance our storm response, and help us provide better information when outages do occur. Self-Optimizing Grid investments have helped Florida customers avoid 7.6 million minutes of interruption during Hurricane Idalia. During Hurricanes Ian and Nicole, our self-healing technology helped avoid nearly 215,000 extended customer power outages, saving more than 200 million minutes of total lost outage time.

Our team rapidly responded to Hurricane Ian, restoring nearly 1 million customers within three days of the storm exiting the state. Twelve hours after Hurricane Nicole exited our service territory, we restored 98% of customers. The Edison Electric Institute awarded DEF its Emergency Recovery Award for DEF's response to Hurricane Nicole.

Most recently on August 30, 2023, Hurricane Idalia made landfall near Keaton Beach in Taylor County, quickly moving ashore between Perry and Salem, with maximum sustained winds of 125 mph. In total, Hurricane Idalia impacted more than 185,000 customers in DEF's service territory which were restored as quickly and safely as possible.

Following the devastation of Hurricanes Ian and Idalia, the Duke Energy Foundation via shareholder dollars gave $745,000 to support local recovery and disaster relief efforts in Florida. This is in addition to $823,000 in grants the company provided since 2021 to support emergency operations centers and nonprofits dedicated to helping residents prepare for and recover from severe weather events.

These results are made possible by the dedication of our employees and the investments this Commission approves for the benefit of customers. These investments are critical for maintaining a cost-effective, safe, reliable, and increasingly cleaner electric service to our customers. In order to make these capital investments possible, DEF must maintain strong, investment-grade credit quality to assure its financial strengths and flexibility and ensure access to capital on reasonable terms, as explained in detail by Mr. Karl Newlin in his testimony.

Q. How does the Company view Customer Service?

A. DEF works tirelessly to provide high-quality customer service. Our customers are at the center of the decisions we make. DEF will continue to enhance the customer experience by building on existing connections with all customers, soliciting customer feedback, being mindful of evolving customer expectations, working to anticipate customer needs, leveraging emerging technologies, and offering dynamic solutions to customer issues. Our employees, who live and work in the communities we serve, along with our Community Relations, Large Account Managers, and Public Affairs teammates who are directly connected to our communities, allow DEF to understand emerging issues, address customers' evolving expectations, inform or confirm business decisions, and build relationships and trust. DEF's investments and programs regarding the customer experience are further explained by Ms. Lesley Quick.

Q. How has DEF improved the customer experience?

A. DEF launched a number of digital tools aimed at improving interactions with our customers. Since launching the advanced language Interactive Voice Response ("IVR") system in 2019, the Company has learned that customers want the ability to self-serve while navigating seamlessly through the IVR. Existing self-service functionality, such as requesting a payment arrangement and reporting a power outage, was improved via voice activated prompts, helping to provide a more positive customer experience. Customer Connect was introduced in fall of 2021 to provide a modern, configurable billing engine that personalizes the customer experience. Customers now have the flexibility to receive additional text notifications, including but not limited to, tree trimming information, bill reminders, and street light repairs. Also in 2021, DEF launched a new Street and Area Light Repair platform which allows both customers and call center specialists to easily report streetlight issues. This platform received a 2022 Best Practices Awards in Outage Restoration by Chartwell, a company that works with utilities to improve customer experience, satisfaction, and operational efficiency. Most recently in February 2024, DEF's Web Portal added a live chat feature upon the successful completion of a pilot program in 2023.

As outlined in Ms. Lesley Quick's testimony, DEF utilizes several tools to measure overall customer satisfaction as well as identifying potential areas of improvements from a customer perspective. These tools include both national benchmarking studies and proprietary relationship and transactional customer satisfaction ("CSAT") studies, CX Monitor surveys, and "Fastrack 2.0."

Q. How does DEF assist customers to pay their bills?

A. DEF recognizes our customers have diverse needs and we strive to accommodate those needs when possible. A variety of billing and payment options are offered to make paying bills simple, secure, and convenient.

For example, there are multiple programs and assistance options designed to support our low-income customers. These programs connect our customers with assistance agencies that administer the Low-Income Home Energy Assistance Program ("LIHEAP") and Elderly Home Energy Assistance Program ("EHEAP"). In 2023, DEF collected approximately $27 million in pledges towards customer electricity bills, as stated in Ms. Lesley Quick's testimony. Since 2020, Duke Energy and our foundation have funded more than $27.5 million in charitable giving across the state of Florida. [2]

One of the programs specially designed to assist our income-eligible customers is the innovative Neighborhood Energy Saver program. This program is offered to residential customers (both homeowners and renters) living in communities objectively identified as areas where the program would be most beneficial using federal and state guidelines and census data. Through this program DEF will assess each home to determine if it qualifies for free attic insulation, duct sealing and more. Since the Neighborhood Energy Saver program's inception in 2006, the

[2] Charitable giving from the Duke Energy Foundation is not recovered from customers.

Company has implemented it in more than 65 communities across Florida and installed more than 700,000 energy efficiency improvements in more than 49,000 income-eligible customers' homes.

IV. EMPLOYEE AND STAKEHOLDER ENGAGEMENT

Q. How does DEF approach employee engagement?

A. DEF has deep roots in the communities we serve, which is formed by our dedication to help build and nurture the places we call home. DEF has approximately 3,700 dedicated and engaged employees and close to 3,800 retirees that live and/or work in the communities we serve. Our employees deliver critical services to our customers every day. We believe when employees are engaged, they are motivated to show up to work every day to contribute to our purpose of powering the lives of our customers and the vitality of our communities. Just like our customers, our employees want to feel heard, included, and enabled.

Additionally, DEF encourages employees to participate in Employee Resource Groups ("ERGs") which are networks of employees formed around a common dimension of diversity. The goals and objectives of ERGs align with the Company's mission, values, and priorities. Throughout the year, Florida ERGs participate in numerous local events to support initiatives focused on supporting our communities and connecting our employees to causes that are close to their hearts. ERGs help DEF value the differences among employees, customers, and the communities we serve.

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Q. Please describe DEF's efforts to maintain a robust employee pipeline.

A. Our most valuable asset is our people, and they are the foundation of our Company. DEF is constantly working to attract a future workforce that will have the skills necessary to build and maintain a changing energy infrastructure. DEF attends career fairs at major Florida universities such as USF, UCF, UF, and FAMU to recruit quality candidates. Also, recruiting through lineworker programs, like the one we have with St. Petersburg College, and other similar high-caliber State college programs helps ensure we develop a skilled workforce that is representative of the communities we serve. DEF hires between 40-100 Apprentices each year to advance Line Technicians and replenish the attrition we experience. Mr. Brian Lloyd further explains this program in his testimony.

DEF is also proud to stand with the 1.5 million veterans throughout Florida, and this includes more than 360 DEF employees who have served or are currently serving in the military. We have a long history of providing career opportunities to our military, including transitioning military service members, veterans, and military spouses. "Together We Stand," our internal veteran-network group, includes over 450 members, mentors, and new hires, works to help veterans adjust to Duke Energy's culture, and eases the transition to civilian life.

Q. How does DEF engage with external stakeholders?

A. At DEF, we believe that we achieve better outcomes through collaboration and engagement, especially when we work closely with the organizations and leaders that are trusted and valued within the communities we serve. Based on our

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experiences, we know transparency, inclusivity, trust, collaboration, and patience are some of the key components to building relationships and unlocking new possibilities within our communities. We are committed to serving as a strong community partner, actively working to help ensure the communities we operate in are valued and respected. DEF proactively engages with our stakeholders by listening, seeking feedback, and responding to questions and concerns. Our plans to build a smarter energy future for our customers and communities are developed through collaboration with stakeholders and actions we believe are necessary to maintain reliability on which our customers depend.

DEF understands that our infrastructure projects can have significant impacts on the public. We seek opportunities for public input and ways to engage with the public at every stage of our projects. We use multiple channels for communications which depend on the specific project or initiatives. Some of these include letters and postcards, web sites, automated calls and text, door-to-door outreach, social media, and one-on-one meetings with groups such as homeowners' associations or community associations. By involving the public and diverse stakeholders early and often, we hope to foster collaboration and look for ways to mitigate impacts as much as possible.

DEF has Government and Community Relations Managers who live and work in the communities we serve because we recognize that different communities have different needs. Having these individuals at the ground level in our communities allow us to get first-hand knowledge and experience on the issues that matter to our customers.

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V. TRANSFORMATION – PAST AND FUTURE

Q. What was the 2021 Settlement Agreement, and how did it allow DEF to transform its business?

A. The 2021 Settlement Agreement was a comprehensive agreement, reached with a wide range of customer groups and approved by the Commission, that allowed the Company to continue investments while moderating rate impacts for customers. The 2021 Settlement Agreement facilitated additional base rate investments across our system to maintain reliability and meet customer demands. These investments and their positive impact for our customers are covered in detail in the testimonies of Mr. Brian Lloyd, Mr. Edward Scott, Mr. Reginald Anderson, Ms. Vanessa Goff, and Ms. Lesley Quick. In general, DEF has been able to continue to modernize the grid and improve reliability; added 600 MWs of solar generation to the system; introduced innovative programs for our customers, like Customer Connect and made enhancements to our IVR and online portal systems; and implemented the Vision Florida Pilot program to support innovative technologies. Finally, the settlement allowed DEF to leverage DOE funds to defer otherwise appropriate and necessary base rate increases, as explained in the testimony of Ms. Marcia Olivier.

Q. You mentioned the building of solar plants. Please provide more details on those solar investments.

A. As explained in the testimonies of Mr. Reginald Anderson and Ms. Vanessa Goff, between 2022 and 2023, DEF placed in service eight solar sites resulting in an additional 600 MWs of solar generation to our system. At the end of 2024, DEF's solar generation fleet will consist of a combined investment of over $2 billion in grid-tied solar power plants providing about 1,500 MWs of emission free, clean generation with approximately 5 million solar panels installed across DEF's service area. This continued commitment to solar investments is also creating fuel savings for our customers, as explained in further detail in Mr. Benjamin Borsch's testimony.

Q. What else has DEF accomplished since the 2021 Settlement Agreement?

A. As detailed in Mr. Reginald Anderson's testimony, DEF recently completed a heat rate improvement project at the Osprey plant. The project involved installing some of the newest combustion technology, resulting in an increased unit capacity of approximately 55 Megawatts, bringing the plant total output to about 650 Megawatts. The increased unit efficiency translates into fuel savings to benefit our customers.

Q. Does DEF plan to continue its investment in solar?

A. Yes, as explained by Ms. Vanessa Goff and Mr. Benjamin Borsch, DEF plans to build 14 additional solar facilities in the 2025-2027 test years. Upon completion of these solar facilities, nearly 15% of DEF's generation will come from solar energy, which will be enough to power over 500,000 residential customers with clean, cost-effective energy. These plants will provide approximately $550 million in

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cost effective savings for our customers, while also reducing fuel costs and increasing fuel diversity on DEF's system.

Q. What other transformative measures does DEF intend to undertake?

A. This rate case request will facilitate additional heat rate efficiency projects, like the one discussed above. As explained by Mr. Reginald Anderson, some of the requested capital investment will fund additional projects at our combined cycle units, Bartow, Citrus, Hines, Osprey, and Tiger Bay.

In addition, DEF will invest in an innovative battery energy storage system ("BESS") project, the Powerline BESS Project, which is a 100-Megawatt lithium-ion energy storage facility with a 2-hour duration maintained over the asset life. This project is further described in Mr. Hans Jacob's testimony.

VI. RATE REQUEST

Q. What steps has DEF taken to control costs and mitigate financial impacts to its customers?

A. As explained above in connection with the 2021 Settlement Agreement, DEF routinely looks for ways to mitigate rate increases to customers. One such example, as explained in more detail by Ms. Marcia Olivier, was the treatment of expected Department of Energy ("DOE") litigation proceeds. By accelerating those funds and giving customers the benefit of those funds, DEF was able to avoid a rate increase that was otherwise necessary. In addition, as explained by Mr. Reginald Anderson, Mr. Brian Lloyd, Mr. Ed Scott, Ms. Vanessa Goff, and Mr. Michael

O'Hara, the Company continually looks for ways to drive costs out of the business. This is reflected by the mostly flat operating and maintenance ("O&M") expenses across the last five years. The Company also maintains a strong balance sheet and good credit rating, which lowers the cost of borrowing money, as explained further by Mr. Karl Newlin. Witness Newlin also describes the importance to customers of DEF maintaining its financial strength so as to continue to provide cost-effective, safe, reliable, and increasingly cleaner electric service.

Q. What are the primary drivers for DEF's rate increase request?

A. DEF remains committed to providing customers electric service in the most cost-efficient manner possible by continuing to: (1) add solar generation and energy storage capacity; (2) make the energy grid even more reliable and resilient; and (3) improve the efficiency and flexibility of existing generating plants to help lower fuel costs while proactively managing the changing grid. DEF is also prudently exploring developing technologies to be better prepared for the future.

DEF will invest $1.5 billion in 1,050 Megawatts of new solar generation capable of powering more than 300,000 homes at peak production from 2025-2027. This investment includes fourteen (14) new 74.9-Megawatt solar power plants plus a 100-Megawatt energy storage project capable of releasing up to 200 Megawatt-Hours of energy every day. The cost of these additional solar power plants is partially offset by available production tax credits, and the energy storage project is eligible for investment tax credits, both from the Inflation Reduction Act, as further discussed by Mr. John Panizza. As a result, DEF customers will receive

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reliable, clean solar power generation at a reduced cost that otherwise would not be available to them. These investments are explained in more detail by Ms. Vanessa Goff and Mr. Benjamin Borsch.

DEF will also invest $3.3 billion from 2025 through 2027 in its transmission and distribution systems to continue to provide reliable, safe electric service to customer homes and businesses. These investments will ensure these systems can provide reliable and safe electric service directly to the customer under the transition to cleaner generation sources spread more widely across DEF's service area, including at the customer's own location from solar rooftop generation. These investments are further described by Mr. Brian Lloyd and Mr. Edward Scott.

DEF must continue to invest in its existing generation fleet for its customers. DEF also plans to invest $113 million in advancements in combustion turbine technology at its existing combined cycle generation plants to increase generation capacity by an additional 428 Megawatts by 2026. This additional combined cycle generation resulting from improvements in combustion turbine technology will provide generation that can more readily meet changes in load on DEF's system and will generate fuel savings for DEF's customers. Mr. Reginald Anderson further describes these investments in his testimony.

In addition to the major cost drivers described above, DEF faces increasing long-term debt interest rates, increasing depreciation expense, declining wholesale sales, and the amortization of deferrals from the 2021 Settlement Agreement that are driving incremental revenue requirements in 2025 through 2027. These factors are further described in Ms. Marcia Olivier's testimony.

Q. What is the ultimate increase that your Company is seeking in this rate case?

A. DEF is requesting an increase of $593 million beginning January 1, 2025, $98 million beginning January 1, 2026, and $129 million beginning January 1, 2027. These increases will facilitate the investments described above, and in the testimonies of DEF's other witnesses, to continue to transform DEF's system to continue providing safe and reliable service to its customers.

Q. Is this rate request necessary for the Company to maintain a strong financial position?

A. Yes, and it is important to DEF's customers that we maintain that strong financial position. DEF is investing and will continue to invest in our infrastructure to make it more resilient, smarter, cleaner, and more efficient. It is our responsibility to plan ahead and make these important investments efficiently and prudently. To deliver on these promises, it is critical that we maintain a strong financial position and thereby ensure that the Company has the financial strength and flexibility to not only fund long-term capital requirements, but to ensure the ability to meet short-term funding needs as well. The single-most determinative factor of a healthy balance sheet and strong financial position is timely recovery of costs and the ability to generate cash flows sufficient to meet obligations as they become due, in all market conditions.

The Company is therefore requesting a capital structure of 53% equity and 47% debt with a return on equity ("ROE") of 11.15%. In support, Mr. Karl Newlin presents testimony explaining how the Company can attract debt and equity investors on appropriate terms. The cost of long-term debt is directly supported by the Company's financial strength, cash flows, market access, and attractive credit ratings. In a rising interest rate environment, the lower the Company's long-term debt rate the more beneficial to customers, which is one example that demonstrates the importance of attracting capital on reasonable terms to fund the projects needed to serve our customers. Mr. Adrien McKenzie presents testimony supporting his conclusion that cost of capital should be set at a return on equity of 11.15%.

Q. Who are the other witnesses presenting testimony in support of the Company's application in this proceeding?

A. The Company's other witnesses filing direct testimony in support of this case are:

1. Adrien McKenzie: return on equity and capital structure expert;
2. Brian Lloyd: necessary investments for distribution or Customer Delivery, as well as reliability performance;
3. Benjamin Borsch: integrated resource planning, load and sales forecasts, and cost-effectiveness for proposed solar units;
4. Edward Scott: necessary investments for transmission, as well as reliability performance;
5. Hans Jacob: battery storage investment;
6. James McClay: asset optimization mechanism;
7. Jeffrey Kopp: dismantlement cost expert;
8. John Panizza: tax issues including production tax credits;

9. Karl Newlin: cost of capital, capital structure, and financing objectives;
10. Lesley Quick: customer service and customer programs;
11. Marcia Olivier: revenue requirements and cost of service;
12. Matt Chatelain: rate design and proposed tariff changes;
13. Michael O'Hara: forecasting methodology;
14. Ned Allis: depreciation expert;
15. Nicole Aquilina: historic accounting practices and books;
16. Rebekah Buck: service company and affiliate allocations;
17. Reginald Anderson: necessary investments for generation or RRE, as well as plant performance;
18. Shannon Caldwell: total compensation, benefits, and human resources;
19. Tim Duff: electric vehicle off-peak credit program; and
20. Vanessa Goff: solar unit development.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Ned W. Allis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	**Docket No. 2024025-EI Submitted for Filing: April 2,2024**

DIRECT TESTIMONY

OF

NED W. ALLIS

On Behalf of Duke Energy Florida, LLC

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I. Introduction

Q. Please state your name and business address.

A. My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

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

A. I am Vice President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"). Gannett Fleming provides depreciation consulting services to utility companies in the United States and Canada.

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

A. As Vice President, I am responsible for conducting depreciation, valuation, and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for Gannett Fleming's proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in

Easton, Pennsylvania. I joined Gannett Fleming in October 2006 as an analyst. My responsibilities included assembling data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. I also developed and maintained Gannett Fleming's proprietary depreciation software. In March of 2013, I was promoted to the position of Supervisor, Depreciation Studies. In March of 2017, I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President.

I am a current member and past president of the Society of Depreciation Professionals (the "Society"). The Society has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 2011 and was recertified in March 2017 and January 2022. I also serve on the faculty for training offered by the Society and am an instructor for the Society's "Introduction to Depreciation," "Life and Net Salvage Analysis," "Analyzing the Life of Real-World Property," "Analyzing Net Salvage in the Real World" and "Depreciation and Ratemaking Issues" courses. I am also an associate member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

I have submitted testimony on depreciation related topics to the Florida Public Service Commission ("FPSC" or "Commission"), the Federal Energy Regulatory Commission ("FERC"), and before the regulatory commissions of the states of California, Connecticut, District of Columbia, Illinois, Kansas, Maryland, Massachusetts, Maine, Missouri, Nevada, New Hampshire, New Jersey, New York, Rhode Island, Tennessee, Virginia, and Washington. I have also assisted other witnesses in the preparation of direct and rebuttal testimony in two Canadian provinces. Exhibit NWA-2 provides a list of depreciation cases in which I have submitted testimony.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by the Society of Depreciation Professionals: "Depreciation Basics," "Life and Net Salvage Analysis," and "Preparing and Defending a Depreciation Study."

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit NWA-1, 2024 Depreciation Study
- Exhibit NWA-2, List of Cases in which Ned W. Allis Submitted Testimony
- Exhibit NWA-3, Summaries of Depreciation Accruals Using Existing and Proposed Depreciation Rates

Q. What is the purpose of your testimony?

A. I am sponsoring the results of Duke Energy Florida, LLC's ("DEF" or the "Company") depreciation study (the "2024 Depreciation Study" or "Study"), filed on behalf of DEF with the Commission, which is provided as Exhibit NWA-1 to my testimony. The service life and net salvage estimates in the Study are based in part on the analysis of historical data through December 31, 2022. The depreciation rates provided in Exhibit NWA-1 are based on the projected balances of depreciable electric properties in service as of December 31, 2024, the effective date of the depreciation study.

Q. Please summarize your testimony.

A. My testimony will explain the methods and procedures of the 2024 Depreciation Study and will set forth the annual depreciation rates that result from the Study. I also provide additional detail on each section of the Study in my testimony.

The overall result of the 2024 Depreciation Study is an increase in DEF's depreciation rates over the currently approved rates, which will increase DEF's total depreciation expense as of December 31, 2024 by approximately $44.2 million. As I detail later in my testimony, this increase is primarily due to plant and reserve activity since the last depreciation study, as well as more negative net salvage estimates for certain transmission and distribution plant accounts. The $44.2 million increase does not include the recovery of regulatory assets related to depreciation and cost of removal, which will be recovered through a separate amortization.

II. 2024 Depreciation Study

Q. Please define the concept of depreciation.

A. The Uniform System of Accounts defines depreciation as:

> *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

Q. In preparing the 2024 Depreciation Study, did you follow generally accepted practices in the field of depreciation?

A. Yes. The methods, procedures and techniques used in the Study are accepted practices in the field of depreciation and are detailed in my testimony.

Q. Please describe the contents of the 2024 Depreciation Study.

A. The Study is presented in eleven parts:

[1] 18 C.F.R. 101 (FERC Uniform System of Accounts), Definition 12.

- Part I, Introduction, presents the scope and basis for the 2024 Depreciation Study;
- Part II, Estimation of Survivor Curves, explains the process of estimating survivor curves and the retirement rate method of life analysis;
- Part III, Service Life Considerations, discusses factors and the informed judgment involved with the estimation of service life;
- Part IV, Net Salvage Considerations, discusses factors and the informed judgment involved with the estimation of net salvage;
- Part V, Calculation of Annual and Accrued Depreciation, explains the method, procedure and technique used in the calculation of annual depreciation expense and the theoretical reserve;
- Part VI, Results of Study, sets forth the service life estimates, net salvage estimates, annual depreciation rates and accruals and theoretical reserves for each depreciable group. This section also includes a description of the detailed tabulations supporting the 2024 Depreciation Study;
- Part VII, Service Life Statistics, sets forth the survivor curve estimates and original life tables for each plant account and subaccount;
- Part VIII, Net Salvage Statistics, sets forth the net salvage analysis for each plant account and subaccount;

- Part IX, Detailed Depreciation Calculations, sets forth the calculation of average remaining life for each property group;
- Part X, Detail of Generation Plant, provides a description of the Company's generating units and provides a discussion of the considerations that inform the service life and net salvage estimates for each plant account and the probable retirement dates for each generating unit; and
- Part XI, Detail of Transmission, Distribution and General Plant, provides a description of transmission, distribution and general plant by account and provides a discussion of the considerations that inform the service life and net salvage estimates for each plant account.

Q. Please identify the depreciation method that you used.

A. I used the straight line method of depreciation, remaining life technique, and the average service life (or average service life – broad group) procedure. The annual depreciation accruals presented in my study are based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

Q. What are your recommended annual depreciation accrual rates for DEF?

A. My recommended annual depreciation accrual rates are the remaining life depreciation rates set forth in Exhibit NWA-1.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group - that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase. The next two sections of my testimony will explain each of these phases of the study.

III. <u>Service Lives and Net Salvage</u>

Q. Please describe the first phase of the 2024 Depreciation Study, in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life and net salvage study consisted of compiling historic data from records related to DEF's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from management and operating personnel concerning accounting and operating practices and plans; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. Did Gannett Fleming physically observe DEF's plant and equipment as part of the 2024 Depreciation Study?

A. Yes. For the 2024 Depreciation Study, we held meetings with operating personnel and conducted field visits to DEF properties to observe representative portions of plant. The meetings and field reviews were conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. What facilities did you observe?

A. In connection with the preparation of the 2024 Depreciation Study, Gannett Fleming visited the following facilities and observed operations and maintenance practices at each location:

- Crystal River Generating Station North
- Citrus Combined Cycle Plant
- Hines Energy Combined Cycle Plant
- Osceola Solar Plant

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For the Company's previous depreciation study, I visited and observed the following facilities:

- Crystal River Generating Station North
- Crystal River Generating Station South
- Anclote Steam Plant
- Bartow Combined Cycle Plant
- Bartow Peaker

A. Service Lives

Q. What is the process for the estimation of service lives in the 2024 Depreciation Study?

A. The process for the estimation of service lives was based on informed judgment that incorporated a number of factors, including the statistical analyses of historical data, general knowledge of the property studied, and information obtained from field trips and management meetings. The method of estimation for each depreciable group depended on the type of property studied for each account. "Mass property" refers to assets such as poles, wires and transformers that are continually added and replaced. Depreciable transmission, distribution and general plant assets were studied as mass property. "Life Span property" refers to assets such as power plants for which all assets at a facility are expected to retire concurrently. The processes of estimating service life for mass property and life span property are described in the following sections.

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1. Mass Property

Q. What historical data did you analyze for the purpose of estimating service life characteristics for mass property?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1943 through 2022. The transactions included additions, retirements, transfers, and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of December 31, 2022.

Q. What methods are generally used to analyze service life data?

A. There are two methods widely used in a typical depreciation study to estimate a survivor curve for a group of plant assets; these are the simulated plant balances method and the retirement rate method.

The simulated plant balance method is used for property groups for which the retirements of property by age are not known. However, it does require continuous records of annual plant activity and year-end plant balances. The method suggests probable survivor curves for a property group by successively applying a number of alternative survivor curves to the group's historical additions in order to simulate the group's surviving balance over a selected period of time. One of the several survivor curves which results in simulated balances that conform most closely to the book balance may be considered to be the survivor curve which the group under study is experiencing.

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. It is the preferred method when sufficient data are available. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts. DEF maintains aged accounting data (meaning that the vintage year is recorded for each addition, retirement, or transfer), and thus the data at DEF are kept in a manner that enables the use of the retirement rate method.

The application of the retirement rate method is illustrated through the use of an example in Part II of the 2024 Depreciation Study. The retirement rate method was used for mass property accounts (i.e., depreciable transmission, distribution, and general plant accounts). As I will discuss in the next section on life span property, the retirement rate method was also used for the estimation of interim survivor curves for production plant accounts.

Q. Did you use statistical survivor characteristics to estimate average service lives of the property?

A. Yes. I used Iowa-type survivor curves.

Q. What is an "Iowa-type survivor curve," and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and expectations regarding future retirements. Iowa-type curves have been accepted by every state commission, including this Commission.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, an Iowa 40-R2 designation indicates an average service life of forty years; a right-moded, or R-type curve (the mode occurs after average life for right-moded curves); and a moderate height, two, for the mode (possible modes for R-type

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curves range from 1 to 5).[2] The Iowa curves are discussed in more detail in Part II of Exhibit NWA-1.

Q. How are Iowa type survivor curves compared to the historical data for the purpose of forecasting service lives?

A. For each depreciable property group, original life tables are developed from the Company's historical records of aged additions, transfers, and retirements. Original life tables can be developed using the full experience of historical data. Original life tables can also be developed using different ranges of years of activity, such as the most recent 30 or 40 years of experience. The range of transaction years used to develop a life table is referred to as an "experience band," and the range of vintages used for the life table is referred to as a "placement band."

Once life tables have been developed using the retirement rate method, specific Iowa curves can be compared both visually and mathematically to the life tables. For visual curve matching, Iowa survivor curves are plotted on the same graph as an original life table, and the points of the curves are visually compared to the life table to assess how closely the Iowa curve matches the historical data. For mathematical curve matching, Iowa curves are compared to an original life table mathematically using an algorithm that compares the differences between

[2] There are also half-mode curves (e.g., R1.5) that are the average of the full mode curves.

an Iowa curve and the original life table.

For both visual and mathematical curve matching, not all of the historical data points should be given the same consideration, as different data points on a life table will have different significance based on both the level of exposures (i.e., the amount of assets that has survived to a given age) and the level of retirements. For example, data points for later ages in an original life table may be based on the experience of a small number of units of property. Due to a smaller sample size, these data points would not provide as meaningful information as earlier ages. Additionally, the middle portion of the curve is where the largest portion of retirements occurs. This portion of the curve therefore often provides the best indications of the survivor characteristics of the property studied.

Q. Can you provide an example of the process of fitting Iowa curves to an original life table?

A. Yes. Account 364, Poles Towers and Fixtures provides a good example of this process. For this account, the life table for the overall experience and placement bands is shown on Exhibit NWA-1, pages VII-97 to VII-100. The original life table develops the percent of plant that has survived to each age for the experience and placement bands. The representative data points from this life table are depicted graphically on Exhibit NWA-1, page VII-96.

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Also shown on page VII-96 is the 40-R3 survivor curve. As can be seen in the chart, this curve is a visually good match of the historical data, as the smooth line depicting the 40-R3 survivor curve is close to the historical data points for most ages. It is a particularly good fit through age 43.5, including many of the data points that are roughly between about 80% surviving and 20% surviving. For this account, these data points provide the most information on the survivor characteristics for this account. The dollars exposed to retirement after age 43.5 comprise less than 1% of the total investment exposed to retirement for this account. The 40-R3 is also a good mathematical fit of the historical data. The degree of mathematical fit can be measured by the residual measure,[3] which is a normalized sum of squares difference between the original life table and a given Iowa curve. The residual measure for the 40-R3 survivor curve and the data points through age 43.5 from the original life table is 1.47, which is considered to be a good fit.[4] The statistical analysis for this account, using both visual and mathematical techniques, therefore indicates that the 40-R3 survivor curve provides a good representation of the historical mortality characteristics for the account.

Q. Is the statistical analysis of historical data based on the retirement rate

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[3] The residual measure is the square root of the total sum of the squares of differences between points on the original and smooth curves divided by the number of points.

[4] The smaller the residual measure, the more closely the Iowa curve mathematically matches the original life table.

method the only consideration in estimating service life?

A. No. The estimation of service life is a forecast of the future experience of property currently in service, and therefore informed judgment that incorporates a number of factors must be used in the process of estimating service life. The statistical analysis can provide a good indication of what has occurred for the Company's assets in the past, but other factors can affect the service lives of the assets going forward. Further, the historical data often does not provide a definitive indication of service life. For these reasons other factors must be considered when estimating future service life characteristics.

Q. Was the process for estimating service lives for other accounts similar to Account 364?

A. Yes. A similar process for estimating service life was used for other mass property accounts. The estimated survivor curves for each account can be found in Part VII of the 2024 Depreciation Study. A narrative description of considerations for each estimate can be found in Part XI of the study.

2. Life Span Property

Q. What method was used to estimate the lives of production facilities?

A. For production facilities the life span method was used to estimate the lives of electric generation facilities, for which concurrent retirement of the entire facility is anticipated. In this method, the survivor characteristics of such facilities are described by the use of interim retirement survivor curves (typically Iowa curves) and capital recovery dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the facility. For a power plant, examples of interim retirements include the retirement of piping, boiler tubes, condensers, turbine blades, and rotors that occur during the life of the facility. Interim survivor curves were developed using the retirement rate method in a manner similar to that used for mass property. The capital recovery date, an estimate of the probable retirement date of a facility based on its anticipated operating life, affects each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age as of that date. The life span of the facility is the time from when the plant is originally placed in service to the expected date of its eventual retirement (i.e., the capital recovery date).

The use of interim survivor curves, truncated at the estimated capital recovery dates, provides a consistent method of estimating the lives of several years' installation for a particular facility inasmuch as a single concurrent retirement for all the years of installation will occur at that specified date.

Q. Is the life span method widely used in the electric industry to determine the depreciation rates for production plants?

A. Yes. The life span method has been used previously for the Company and for other Florida utilities. My firm has also used the life span method in performing depreciation studies presented to many public utility commissions across the United States and Canada, and the life span method is the predominant method used for property such as production plants.

Q. Are interim survivor curves the most common method of estimating interim retirements for life span property?

A. Yes. The use of interim survivor curves to estimate interim retirements is also the predominant method of estimating interim retirements for assets such as power plants.

Q. What are the capital recovery dates and what was your basis for each selection?

A. The capital recovery dates estimated in the study are set forth on Exhibit NWA-1 on pages III-5 through III-7. The capital recovery dates are based on a number of factors, including the operating characteristics of the facilities, the type of technology used at each plant, environmental and other regulations, and the Company's outlook for each facility. Capital recovery dates are specific to each generating unit, and, therefore, the characteristics for each generating unit are considered when estimating a capital recovery date. Typically, the owner and operator of each facility best understands the operation and the outlook of each power plant and is therefore in the best position to determine the most probable retirement of each facility. The Company performed an analysis of the life span for its steam, combined cycle, simple cycle, and solar power plants. I have discussed the estimated life span of each facility with DEF. DEF has retired a number of generating units in recent years and the experienced life spans of these retired facilities were also reviewed. Additionally, I incorporated my firm's experience performing depreciation studies for other utilities and our knowledge of other generating facilities and confirmed that DEF's estimates are reasonable and within the range of typical estimates in the industry.

This process results in capital recovery dates for the 2024 Depreciation Study that are, in my judgment, the most reasonable based on the current information available. Further discussion of these estimates can be found in Part X of Exhibit NWA-1, as well as later in this testimony.

Q. What are the life span estimates for steam generating plants?

A. The Company has retired many of its steam generating plants. The two that remain are Crystal River Units 4 and 5 and the Anclote generating station. Crystal River Units 4 and 5 are coal-fired generating units placed in service in 1982 and 1984. These units are expected to be retired in 2034, which will result in life spans of 52 and 50 years, respectively.

Anclote is a steam generating facility with two units that were placed in service in 1974 and 1978. The facility was converted to use natural gas within the last 15 years. The expected retirement date for this plant is 2029, which will result in life spans of 55 and 51 years, respectively.

Q. Has the Company retired any steam generating plants in recent years?

A. Yes. The Company has retired a number of steam generating plants. The facilities retired, as well as the retirement date and life span of each facility, are summarized in Table 1 below. The actual experienced life spans for these units ranged from 46 to 63 years, with an average life span of approximately 54 years. This experience further supports the 50- to 55- year life spans for the Company's remaining steam generating plants.

Table 1: Retirements of DEF Steam Generating Units

Generating Unit	Retirement Date	Life Span
Crystal River Unit 1	2018	52
Crystal River Unit 2	2018	49
Bartow Unit 1	2009	51
Bartow Unit 2	2009	48
Bartow Unit 3	2009	46
Suwannee River Unit 1	2016	63
Suwannee River Unit 2	2016	62
Suwannee River Unit 3	2016	60

Q. What is the life span estimate for the Company's combined cycle generating facilities?

A. The life span estimate for the combined cycle facilities is 40 years. This

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estimate is the same as currently used for DEF's combined cycle facilities.

Q. How does a 40-year life span compare to the range of estimates by others in the industry for combined cycle power plants?

A. A 40-year life span is within the range of typical estimates for combined cycle plants in the industry. Estimates for other utilities have most commonly been in the 35- to 40-year range.

Q. Has the Company retired any combined cycle power plants?

A. No. The Company's oldest combined cycle plants are around 25 years of age and, therefore, have not been in service long enough to experience 40-year life spans. However, there have been two combined cycle facilities in the state of Florida that have been retired in recent years. These are FPL's Putnam and Lauderdale plants. The experienced life spans for these facilities range from 25 years to 37 years. While somewhat shorter than the recommended life span for DEF's combined cycle plants, these life spans are supportive that the current 40-year life span is reasonable for combined cycle plants.

Table 2: Retirements of Combined Cycle Generating Units in Florida

Generating Unit	Retirement Date	Life Span
Putnam Unit 1	2014	36
Putnam Unit 2	2014	37
Lauderdale Unit 4	2018	25

Lauderdale Unit 5	2018	25

Q. What are the life span estimates for other facilities?

A. The life spans for the Company's simple cycle generating facilities vary and are dependent on the specifics of each facility. The current 30-year life span is recommended for the Company's solar facilities.

Q. In addition to the life span, you have also recommended estimates for interim retirements. Is the estimation of interim retirements using the retirement rate method similar to the process of estimating survivor curves for mass property?

A. Yes. Similar to mass property, the interim survivor curve estimates are based on informed judgment that incorporates actuarial analyses of historical data using the retirement rate method of analysis. Iowa survivor curves have been estimated for each plant account which, combined with the life span estimate for each generating unit, provide the overall survivor curve, average service life and average remaining life for each plant account at each generating unit. A narrative discussion of the considerations for the estimation of interim survivor curves for each account can be found in Part X of the 2024 Depreciation Study. Graphical depictions of the interim survivor curves estimated for each generation plant account are presented in Part VII of the study.

Q. Are there any assets expected to be installed before the next depreciation

study for which you recommend service life estimates and depreciation rates?

A. Yes. The Company plans to add the Powerline battery energy storage system, a 100 MW / 200 MWh battery storage facility, by the end of 2027. Based on guidance in the FERC Uniform System of Accounts[5], by the time the facility is in service these assets will be accounted for in separate subaccounts of a new FERC Account 387. The overall expected life of the facility is 15 years and, while some components of the facility, such as power inverters, could potentially have shorter lives than other components of the facility, the overall 15-year life is reasonable for each of the subaccounts. These estimates can be considered in future studies as more information about the operations of emerging technologies such as battery energy storage systems ("BESS") becomes more available.

The overall recommendation for these Powerline energy storage assets is a 15-S3 survivor curve, 0% net salvage and 6.67% depreciation rate. While there is the potential for negative net salvage for these assets due to the costs to retire, remove and dispose the equipment at the facility, any such costs are expected to be dismantlement costs at the end of the life of the facility and would be incorporated into future dismantlement accruals.

[5] Effective 1/1/2025 per Federal Register Doc. 2023-14994 filed 10/4/2023.

B. Net Salvage

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Thus, net salvage is considered to be a component of the cost of an asset that is recovered through depreciation.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period (e.g., one year), it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost, and the net salvage value.

For example, the full recovery of the service value of a $1,000 transformer may include not only the $1,000 of original cost, but also, on average, $300 to remove the transformer at the end of its life less $150 in salvage value. In this example, the net salvage component is negative $150 ($150 - $300), and the net salvage percentage is negative 15% (($150 - $300)/$1,000).

Q. Please describe the process you used to estimate net salvage percentages.

A. The net salvage estimate for each plant account is based on informed judgment that incorporates the analysis of historical net salvage data. I reviewed net salvage data from 1975 through 2022. Cost of removal and salvage were expressed as a percent of the original cost of the plant retired, both on an annual basis and a three-year moving average basis. The most recent five-year average was also calculated.

Q. Were there other considerations used in developing your final estimates for net salvage?

A. Yes. In addition to the statistical analyses of historical data, I considered the information provided to me by the Company's operating personnel, general knowledge and experience of industry practices, and trends in the industry in general.

Q. Is the same process used for the estimation of net salvage for production plant?

A. The same process is used for interim net salvage for generating plant accounts as is used for the estimation of net salvage for mass property accounts. However, interim net salvage is applied only to the portion of plant expected to be retired as interim retirements. Assets expected to remain in service until the final retirement of a generating facility will experience terminal net salvage – that is, the cost to dismantle the facility.

Q. Do the depreciation rates used for electric generating facilities have a component for dismantlement?

A. No. The dismantlement component of net salvage is not included in the depreciation rates recommended in the 2024 Depreciation Study. Consistent with the longstanding practice of DEF, the Company has made estimates of final dismantlement for their fossil and solar generation facilities, but these costs are handled separately and are not part of the 2024 Depreciation Study. Fossil and solar generation dismantlement costs are included separately in this docket, in testimony sponsored by DEF witnesses Jeff Kopp, Nicole Aquilina, and Marcia Olivier. Therefore, net salvage estimates for fossil and solar production facilities provided in this Study only reflect interim retirement activity.

Q. Has the Company experienced a trend of increasing removal costs?

A. Yes, and as a result net salvage estimates for some accounts are more negative than the current estimates. Costs have increased for a number of reasons, including permitting costs, work requirements, environmental regulations, safety requirements, traffic control and labor and contractor costs.

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Q. Please provide an example of how costs have increased.

A. Distribution poles provide a good example of factors that have resulted in increasing costs to retire assets. DEF's poles are primarily wood poles. The retirement of a wood pole requires a multiple person crew as well as equipment including a pole truck. In addition to the replacement of the actual pole, the Company must also transfer the primary and secondary cable, as well as other devices, from the old pole to the new pole.

Costs for retiring poles have increased for a number of reasons. Labor and contractor costs have increased over time. Permitting costs have increased, as have requirements for traffic control. Each of the factors described here contribute to higher cost of removal going forward than was the case ten or twenty years ago. This trend is consistent with the historical net salvage data, which indicates increasing cost of removal for distribution poles.

Q. Is the trend to higher cost of removal consistent with the experience of other utilities in the industry?

A. Yes. My firm conducts depreciation studies for utilities across the country. The trend towards increasing cost of removal is consistent with the experience of many others in the industry. The reasons that DEF's costs have increased are also experienced by other utilities.

IV. Remaining Lives and Depreciation Rates

Q. Please describe the second phase of the 2024 Depreciation Study, in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life and determined net salvage characteristics to use for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The recommended depreciation rates are based on forecast balances as of December 31, 2024, which is the effective date of the study.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method (also referred to as the straight line method and remaining life technique) of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life, and this rate is applied to the surviving balance of the group's cost. The average remaining life for the group is determined by first calculating the average remaining life for each vintage of plant within the group. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the average remaining life for the group is determined by calculating the dollar-weighted average of the calculated remaining lives for each vintage. The annual depreciation accruals for the group are calculated by dividing the remaining depreciation accruals (original cost less accumulated depreciation less net salvage) by the average remaining life for the group.

Q. Please use an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in the 2024 Depreciation Study.

A. For purposes of illustrating this process I will use Account 368, Line Transformers. The survivor curve estimate for this account is the 35-R0.5, and the net salvage estimate is for negative 15 percent net salvage. A discussion of these estimates, as well as the statistical analyses that support the estimates for this account can be found on Exhibit NWA-1, pages XI-32, and XI-33. The calculation of the annual depreciation related to the original cost of Account 368, Line Transformers as of December 31, 2024, is presented on Exhibit NWA-1, page VI-11. The calculation is based on the 35-R0.5 survivor curve, negative 15 percent net salvage, the attained age, and the book reserve. The calculated annual depreciation accrual and rate are based on the estimated survivor curve and net salvage, the original cost, book reserve, future accruals, and composite remaining life for the account. The calculation of the composite remaining life as of December 31, 2024 is provided in the tabulations presented on Exhibit NWA-1, pages IX-147 and IX-148. The tabulation sets forth the installation year, the original cost, the average service life, the whole life annual depreciation rate and accruals, the remaining life and theoretical future accruals factor and amounts. The average service life weighted composite remaining life of 28.71 years is equal to the total theoretical future accruals divided by the total whole life depreciation accruals.

Q. Did you use this same methodology for the general plant accounts?

A. Yes. This methodology was used for the general plant accounts that are depreciated. However, many of the general plant accounts are amortized in accordance with the Company's current amortization periods. I have not recommended changes in the amortization periods for these accounts.

Q. What were your overall results of the 2024 Depreciation Study?

A. The Study resulted in an increase in average service lives for many accounts. The trend towards longer service lives is not uncommon in the electric utility industry today.

The 2024 Depreciation Study also resulted in increases in negative net salvage (i.e. net salvage estimates that are more negative) for some accounts, which is attributable to the increasing cost of removal discussed previously. A trend to more negative net salvage is also consistent with the experience of many other utilities.

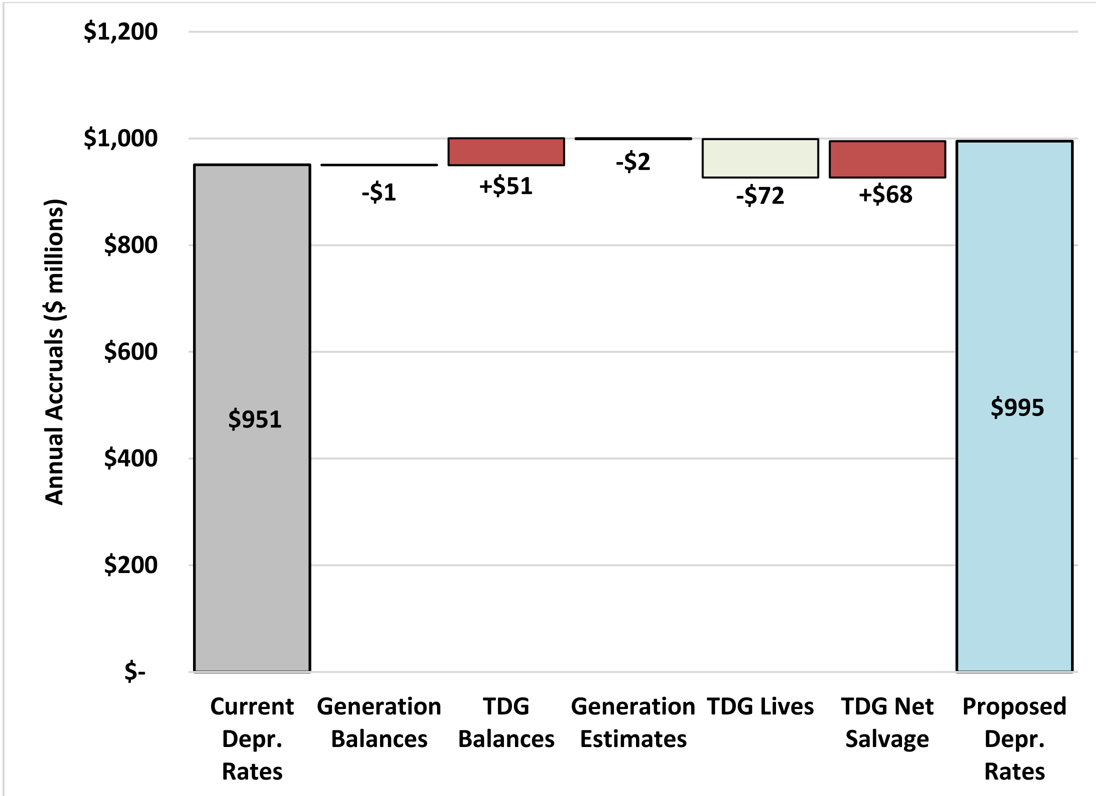
The Study results in an increase of total company depreciation expense of approximately $44.2 million based on plant balances as of December 31, 2024. This increase is primarily due to more negative net salvage estimates for transmission and distribution plant accounts as well as changes to the plant and accumulated depreciation balances since the last study. This increase is partially offset by the service life estimates for transmission and distribution plant accounts, in particular the recommendations for longer service lives for many accounts. The impact of the 2024 Depreciation Study on depreciation expense and accumulated depreciation for each of the Company's test periods is calculated and discussed in the direct testimony of Company witness Marcia Olivier.

V. <u>Factors Affecting Depreciation Expense</u>

Q. What are the major factors that affect the depreciation expense resulting from application of the 2024 Depreciation Study?

A. The changes in annual depreciation rates and expense are shown in Table 2 of the 2024 Depreciation Study and result in an overall increase in depreciation expense of approximately $44.2 million (again, based on plant balances as of December 31, 2024). Much of the increase is not due to the recommended service lives and net salvage in the study but is instead due to plant and reserve activity since the last case and that the current depreciation rates were insufficient to account for this activity. The change in plant and accumulated depreciation balances results in an increase of approximately $51 million in depreciation expense, while the recommended service life and net salvage estimates in the Depreciation Study result in a $6 million decrease in expense. Figure 1 below provides an illustration of the factors that result in the change in depreciation expense resulting from Gannett Fleming's recommendations. The causes of these changes are summarized below.

Figure 1: Summary of Depreciation Changes in the 2024 Depreciation Study



Steam Production: The depreciation expense for this class of plant increased by approximately $5.6 million. The increase in expense is due primarily to the change in balances.

Other Production (Combined Cycle): This class of plant has an overall decrease in depreciation expense of approximately $9.9 million. The primary reason for the decrease is related to a change in balances since the previous study. Specifically, the depreciation rates for rotable parts in the previous study were higher due to lower accumulated depreciation balances (since depreciation was not calculated separately in prior studies to incorporate the shorter lives of these components). The recommended depreciation rates are more aligned with the service life estimate for rotable parts than those currently in effect.

Other Production (Simple Cycle and Solar): This class of plant has an overall increase in depreciation expense of approximately $1.9 million. The primary reason for the increase is related to changes in balances since the previous study.

Transmission, Distribution and General Plant Balances: The use of remaining life depreciation rates means that depreciation rates will often change from study to study even if there are no changes in service lives or net salvage due to plant and reserve activity that has occurred since the last depreciation study. For transmission, distribution, and general plant, recalculating the depreciation rates with the currently approved service lives and net salvage results in an increase in depreciation expense of approximately $51 million. That is, even had there been no changes to the recommended service lives and net salvage for these classes of plant, depreciation would increase by approximately $51 million due to updating for current plant and reserve balances.

Transmission, Distribution and General Plant Service Lives and Net Salvage: The recommended service lives and net salvage for these classes of plant result in a net decrease in depreciation expense of approximately $4 million when compared to the depreciation rates that result from using the current service lives and net salvage. The increase in service lives for several TD&G accounts offsets more negative net salvage estimates for several accounts.

Q. Why do capital additions for production plant result in an increase in depreciation rates?

A. Additions to life span property typically will result in an increase not only to depreciation expense due to a resulting higher plant balance, but also because additions typically increase the depreciation rate for this type of property. For life span property, interim additions (that is, additions added subsequent to the original in service date of the facility) will have a shorter service life than the original installation of the facility. This occurs because the facility has a final retirement date at which time all assets will be retired. Thus, for interim additions, the length of time between installation and the end of the life span of the facility is shorter than for the original installation of the plant.

To help illustrate this concept, consider as an example a power plant that is installed in 1970 for $1 million. For simplicity, assume that there will be no interim retirements and no net salvage. If the plant is retired in 2030, the life span of the facility is 60 years. The average service life for the 1970 vintage is also 60 years. The depreciation rate at the time of the original installation is 1.67%.[6] Assume that in 2000 an additional $500,000 is added to the facility.

[6] Equal to 1/60.

These assets will not have an average service life of 60 years, but instead will have an average service life of 30 years since they will be retired in 2030 with the balance of the plant. That is, the interim additions have a shorter service life than the original addition of the facility.

For this reason, the overall average service life of life span property will decrease as new interim additions are made. Similarly, the annual depreciation rate will tend to increase over time as interim additions occur. After the installation of the 2000 vintage assets the depreciation rate increases to 2.22%[7] from 1.67%. Thus, although the service life estimate for the plant did not change, the depreciation rate increased due to the interim additions to the facility.

This same concept explains many of the increases in depreciation rates for DEF's production plant facilities, as significant additions have occurred at steam and combined cycle plants. All else equal, these additions cause increases in depreciation rates and are a primary factor contributing to the overall increase in depreciation expense resulting from the 2024 Depreciation Study.

VI. **Recovery of Regulatory Assets Related to Depreciation and Cost of**

[7] Equal to ($1,000,000/60+$500,000/30)/($1,000,000+$500,000).

Removal

Q. Please explain the regulatory assets for DEF related to the theoretical reserve imbalance and accumulated depreciation for cost of removal.

A. In the initial order (Order No. PSC-2010-0131-FOF-EI) for Docket Nos. 20090079-EI, 20090144-EI and 20090145-EI, the Commission ordered that the Company amortize a portion of the theoretical reserve imbalance ("TRI") calculated in that case over a four year period, for an annual amount of approximately $5.8 million[8] (I will refer to this as the "TRI Regulatory Asset" in my testimony). After the issuance of that order, the Company filed depreciation rates with FERC in Docket No. ER11-3584-000. FERC ruled that these adjustments "do not conform to our requirements for allocating the costs of utility plant over their service lives" and that such adjustments would be recorded "as regulatory assets in Account 182.3, Other Regulatory Assets, rather than as adjustments to its depreciation reserve."[9] As a result, the amortization of this amount was recorded on the Company's books as a regulatory asset rather than a reduction to accumulated depreciation.

Subsequent to these decisions, the Company entered into a settlement agreement that made changes to these amortizations.[10] The annual $5.8 million amount was replaced with a flexible amortization of accumulated depreciation

[8] See page 52 of Order No. PSC-2010-0131-FOF-EI.
[9] See pages 2 to 5 of the order issued July 15, 2011 in FERC Docket No. ER11-3584-000.
[10] Order No. PSC-2010-0398-S-EI.

related to cost of removal. As a result of that amortization, DEF currently has a regulatory asset on its books of approximately $461 million (I will refer to this as the "COR Regulatory Asset"). This amount was also recorded as a regulatory asset rather than a reduction to accumulated depreciation.

Based on these combined amortizations, the Company initially amortized three-years of the theoretical reserve imbalance at $5.8 million per year and has subsequently recorded the flexible amortization resulting in the $461 million amount discussed above, for a total of approximately $478 million. These amounts have been recorded as regulatory assets on the Company's books and given the history of each of these amortizations, they need to be recovered through future rates.

Q. Because these amounts were reductions to the recovery of the Company's costs for FPSC ratemaking purposes, does this mean the $478 million needs to be recovered as future expense, either as depreciation accruals or the amortization of the regulatory assets?

A. Yes. Because expense has been approximately $478 million lower due to these amortizations, there is an additional $478 million that needs to be recovered than is currently reflected in accumulated depreciation. There are two ways in which these regulatory asset amounts could be recovered: 1) reflect these amounts in accumulated depreciation for FPSC ratemaking purposes and recover the amounts through remaining life depreciation rates; or 2) separately amortize these amounts over a period of time. Because these amounts are related to past depreciation accruals and because the remaining life technique has historically been used in Florida (and is proposed in the Depreciation Study), if option 2 were used then, in my judgment, the remaining lives of the Company's assets would be the appropriate periods over which to amortize these regulatory assets. Because this is effectively the same period of time over which these costs would be recovered through remaining life depreciation rates, this means that the net impact on expense of either option 1 or option 2 should be relatively similar – the primary difference would be whether the costs are recovered through depreciation rates or through a separate amortization.[11]

Q. How have you incorporated these regulatory assets in the Depreciation Study?

A. For the purposes of calculating depreciation rates, these regulatory assets have not been included in the accumulated depreciation balances. Instead, consistent with the Company's 2021 Settlement Agreement,[12] the Company proposes to recover these regulatory assets over the average remaining lives of assets currently in service. The overall average remaining life of all assets in the

[11] I note that there could be some differences depending on how the amortization amounts were calculated, but at least on a conceptual basis the recovery is, in effect, the same.
[12] Paragraph 21.c. of the settlement agreement approved in Order No. 2021-0202-AS-EI states: "DEF will delay the start of amortization of the Cost of Removal ("COR") Regulatory Asset to January 1, 2025 and the recovery period of this regulatory asset shall be no longer than the average remaining service life of the assets, approved in the Company's most recent depreciation study at that time."

depreciation study is approximately 25.50 years, as shown in Table 1 on page VI-11 of the depreciation study.

Q. For the purposes of calculating the theoretical reserve imbalance, have you included the regulatory assets?

A. Yes. For a theoretical reserve imbalance calculation, reflecting these costs in accumulated depreciation results in a more accurate reflection of accumulated depreciation. If these costs were not included in accumulated depreciation, the theoretical reserve imbalance (which is discussed in more detail in the next section) would not reflect the fact that these regulatory assets need to be recovered through future expense.

Q. In Docket No. 20170183-EI, the Company was authorized to recover an additional $50 million in depreciation per year to account for the expected shorter life span for Crystal River Units 4 and 5.[13] How have these amounts been incorporated into the Depreciation Study?

A. The additional recovery for Crystal River Units 4 and 5 of $200 million is accounted for in the present Depreciation Study consistent with what was done in the prior 2019 Depreciation Study. This amount is incorporated into the accumulated depreciation for Crystal River Units 4 and 5. The result is lower depreciation rates for Crystal River Units 4 and 5 than had this $200 million

[13] See pages 38 and 39 of Order No. PSC-2017-0451-AS-EU and page 8 of Order No. PSC-2019-0053-FOF-EI

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amount not been recovered.

VII. Theoretical Reserve Imbalance

Q. What is a theoretical reserve imbalance?

A. A theoretical reserve imbalance ("TRI" or "imbalance") is calculated as the difference between a company's book accumulated depreciation, or book reserve, and the calculated accrued depreciation, or theoretical reserve. I should note that in prior proceedings in both Florida and other jurisdictions, different terms have been used for the theoretical reserve imbalance, including "theoretical reserve variance," "reserve excess," "reserve surplus" or "reserve deficit" and "theoretical excess depreciation reserve." For this testimony I will use the term "theoretical reserve imbalance," which is consistent with the terminology used in the National Association of Regulatory Utility Commissioners' ("NARUC") publication *Public Utility Depreciation Practices*.

Q. What is the book reserve?

A. The book reserve, also referred to as the "book accumulated depreciation" or the "accumulated provision for depreciation," is a running total of historical depreciation activity. It is equal to the historical depreciation accruals, less retirements and cost of removal, plus historical gross salvage. The book reserve also represents a reduction to the original cost of plant when calculating rate

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base.

Q. What is the theoretical reserve?

A. The theoretical reserve is an estimate of the accumulated depreciation based on the current plant balances and depreciation parameters (service life and net salvage estimates) at a specific point in time. It is equal to the portion of the depreciable cost of plant that will not be allocated to expense through future whole life depreciation accruals based on the current forecasts of service life and net salvage. The theoretical reserve is also referred to as the "Calculated Accrued Depreciation" or "CAD."

Q. Is the theoretical reserve the "correct" reserve?

A. No, the theoretical reserve is an estimate at a given point in time based on the current plant balances and current life and net salvage estimates. It can provide a benchmark of a Company's reserve position, but it should not be thought of generally as the "correct" reserve amount. In Wolf and Fitch's *Depreciation Systems*, this point is explained as follows on page 86:

> The CAD is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.

Q. How is a TRI typically addressed in a depreciation study?

A. In most jurisdictions an explicit adjustment to the book reserve is not made. Instead, the remaining life technique is used. When using remaining life technique, there is an automatic adjustment, or self-correcting mechanism, that will increase or decrease depreciation expense to account for any imbalances between the book and theoretical reserves. The 2024 Depreciation Study uses the remaining life technique. The depreciation rates presented in the study therefore already include an adjustment for the theoretical reserve imbalance. No further adjustment is needed.

Q. What is the theoretical reserve imbalance, based on estimates from the 2024 Depreciation Study and plant and reserve balances as of December 31, 2024?

A. The theoretical reserve imbalance estimated in the 2024 Depreciation Study is approximately negative $1.3 billion. That is, the book reserve is approximately $1.3 billion lower than the theoretical reserve from the study. Approximately $427 million of this is reserve imbalance related to the COR Regulatory Asset and TRI Regulatory Asset.[14] The TRI also includes the $200 million in additional recovery of Crystal River Units 4 and 5.

Q. Why should the COR and TRI regulatory liabilities be included in the

[14] $51.3 million of the COR Regulatory Asset is related to plants that have been or will be retired or are not included in the depreciation study. The calculation of the theoretical reserve imbalance in the depreciation study does not include this $51.3 million amount.

calculation of the theoretical reserve imbalance?

A. The theoretical reserve imbalance is a comparison of the depreciation recovered to date on the Company's books to a theoretical amount that is calculated using the current service life and net salvage estimates. Because the regulatory assets are reductions to the amount of depreciation recovered to date, excluding these amounts from the theoretical reserve imbalance will overstate the amount of expense recovered (or, equivalently, will understate the amount that needs to be recovered through future expense). For this reason, the book reserve used for the calculation of the theoretical reserve imbalance in the 2024 Depreciation Study includes the COR and TRI regulatory assets.

Q. What do you recommend for the TRI?

A. Consistent with prior depreciation studies I have performed, my recommendation is to address the theoretical reserve imbalance through remaining life depreciation rates. I do not recommend any additional amortization of the TRI.

Q. Do you recommend any reserve transfers based on the results of the depreciation study?

A. Yes. FPSC Rule 25-6.0436(4)(e) states that "[t]he possibility of corrective reserve transfers shall be investigated by the Commission prior to changing depreciation rates." For the depreciation study, I have reviewed the reserve balances to determine whether any such transfers would be appropriate. There are a handful of depreciable groups for which either there are large negative reserves (which result in high depreciation rates) or for which the future book accruals are negative. I recommend transfers between depreciable groups to address these instances. Specifically, reserve transfers are recommended for certain accounts for Crystal River, Osceola Solar, Other Production facilities that contain rotable parts assets, as well as for Accounts 353, 369, 370, 390, 392 and 396. The net impact of these transfers on accumulated depreciation is zero, as they are merely transfers between depreciable groups. The transfers are all also within the same function of plant and, as a result, the impact on functional book reserves is also zero.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Reginald D. Anderson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC

Docket No. 2024025-EI

Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

REGINALD D. ANDERSON

On Behalf of Duke Energy Florida, LLC

I. Introduction

Q. Please state your name and business address.

A. My name is Reginald D. Anderson, and my business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Vice President of DEF's Power Generation organization.

Q. Please describe your duties and responsibilities as Vice President of DEF's Power Generation organization.

A. I am responsible for providing overall leadership and strategic and tactical planning over employees in DEF's Power Generation organization. In this role, I oversee generation projects, major maintenance programs, outage and project management, fleet retirement strategy, and workforce planning (including departmental staffing and long-term strategies such as organizational alignment, design, retention, and inclusion). I am responsible for billions of dollars in assets including capital and operating and maintenance ("O&M") budgets, and I lead the development of regional succession planning.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Electrical Engineering Technology and a Master of Business from the University of Central Florida. I have 25 years of power plant production experience at DEF in various operational, managerial and leadership positions in fossil steam and combustion turbine plant operations. My experience includes managing new construction, O&M projects and teams and negotiating contracts. Prior to joining DEF, I held various leadership roles with municipal utilities, manufacturing companies, and the United States Marine Corps.

Q. Have you testified before this Commission in any prior proceeding?

A. Yes, I have testified on behalf of DEF in connection with the Environmental Cost Recovery Clause ("ECRC") proceeding, most recently in Docket No. 20230007-EI, which provided estimates of ECRC-recoverable costs that will be incurred in 2024.

II. <u>Purpose and Testimony Summary</u>

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

A. The purpose of my testimony is to provide an overview of DEF's generation fleet and its evolution in the last five years. I present DEF's positive fleet reliability and performance metrics and describe the Company's fleet operating and management philosophy. My testimony also supports the reasonableness of DEF's non-fuel O&M and capital expenditures ("Capex") and provides the Capex and O&M production expenditures for the rate case test period (2025 – 2027). Lastly, I discuss historical O&M expenses and future O&M forecasts, and I describe DEF's cost-saving initiatives and productivity improvements that have been or will be implemented and their corresponding reduction on costs.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared, supervised, sponsored, or co-sponsored the preparation of the following five exhibits to my direct testimony:

- Exhibit RDA-1 is a list of the Minimum Filing Requirements ("MFRs") I am sponsoring or co-sponsoring.
- Exhibit RDA-2 lists the facilities that comprise DEF's current generation fleet.
- Exhibit RDA-3 provides DEF's Heat Rate & Unit Flexibility metrics.
- Exhibit RDA-4 lists and provides an overview of each of the major DEF Generation projects that make up the Company's capital request included in the MFRs for the years 2025-2027.

These exhibits are true and accurate, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. Since the 2021 Settlement Agreement,[1] DEF's generation fleet has continued to grow and evolve with Florida's changing energy landscape. The Company has a history of making investments that provide customers with more reliable, resilient, and cleaner power. DEF's generation fleet is an integral part of the Company's progress. As I explain further below, DEF Generation has invested in solar generation, increasing output by approximately 1,170 MWs in the last five years, while also maintaining an efficient and reliable resource mix. The Company has made targeted investments to increase generating efficiency, which has reduced

[1] Approved by the Commission in Order No. PSC-2021-0202-AS-EI.

fuel costs and emissions all the while improving upon already above-average reliability and performance metrics. Throughout all of this, safety has remained at the forefront, and the Duke Energy and DEF generating fleets have attained industry top decile results for five consecutive years. As the Company looks to future needs, non-fuel O&M and Capex funding will be essential to the continued evolution, flexibility, and positive performance of DEF's generation fleet.

III. Generation Fleet Overview

Q. Please provide an overview of DEF's generation fleet.

A. DEF's generation fleet employs less than 500 people and, as of January 1, 2024, provides more than 12,000 nominal megawatts ("MWs") of total winter generation for DEF customers. The Company's generation portfolio consists of nine combined cycle ("CC") power blocks, two coal-fired steam units, two gas-fired steam units, one cogeneration facility, thirty-four simple cycle combustion turbines ("CTs") and nineteen solar sites. The CC and simple cycle CTs are comprised of units that are dual-fuel, natural gas only, and distillate fuel oil only. Exhibit RDA-2 provides an overview of facilities that comprise DEF's generation fleet.

Q. Has DEF's generation fleet undergone any changes over the last five years?

A. Yes. The DEF generation fleet has undergone a significant transformation over the last five years as it has evolved into a cleaner, more efficient, and more capable fleet. During this timeframe, decisions involving the generation fleet have been guided by the following overarching commitments: (1) providing safe, reliable, efficient, and cost-effective generation; and (2) reducing environmental impacts and ensuring compliance with state and federal regulations. Consistent with, and building upon these commitments, DEF has been active and diligent in advancing solar energy and modernizing its fleet.

For example, from 2018 to 2023, DEF increased generation by constructing and placing into operation 16 solar sites totaling approximately 1,170 MWs of capacity. In addition, DEF expects to place into service another four solar sites in 2024 and 14 solar sites from 2025 through 2027, bringing the total sites in our solar fleet to 34,[2] and providing more than 2,500 MWs of solar capacity. DEF also retired two coal-fired plants in 2018. The table below illustrates the retirements, additions, and unit configuration changes the DEF generation fleet has experienced from 2018 through 2023.

DEF Generation Fleet
Fleet Resource Additions/Retirements
For the Period 2018-2023

			MW Changes	
Year	**Unit**	**Type**	**Retirements**	**Additions**
2018	Citrus 1 and 2	Combined Cycle Natural Gas		1,640
2018	Crystal River 1 and 2	Coal	925	
2018	Hamilton	Solar		75
2019	Lake Placid	Solar		45
2019	Trenton	Solar		75
2019	Higgins	Oil/Gas Combustion Turbine	200	
2020	Columbia	Solar		75
2020	DeBary	Solar		75
2020	Avon Park	Oil/Gas Combustion Turbine	50	
2021	Santa Fe	Solar		75

[2] Excludes several small solar sites on DEF's system ranging from 0.25 MW to 9 MW.

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2021	Twin Rivers	Solar		75
2021	Duette	Solar		75
2022	Sandy Creek	Solar		75
2022	Fort Green	Solar		75
2022	Charlie Creek	Solar		75
2022	Bay Trail	Solar		75
2022	Lake Placid	Battery Storage		18
2022	DeBary CT 1	Oil/Gas Combustion Turbine	50	
2023	Bayboro CT 4B	Oil/Gas Combustion Turbine	25	
2023	Hildreth	Solar		75
2023	High Springs	Solar		75
2023	Hardeetown	Solar		75
2023	Bay Ranch	Solar		75
2023	Osprey	GTOP 7 Upgrade		55
	Total		**325**	**2,883**

During this same period, DEF's generation fleet capacity has increased from approximately 10,000 MWs to over 12,000 nominal MWs of total winter generation.

Q. How has DEF's generating capacity changed since the 2021 Settlement Agreement?

A. As a part of the 2021 Settlement Agreement, DEF received a base rate increase that allowed for the continued investment in all aspects of its business, including generation, to improve the provision of safe and reliable electric service to its customers. Specific to the DEF Power Generation organization, the 2021 Settlement Agreement provided for the construction and recovery of cost-effective solar generating units, and an annual capital expenditure program ranging from approximately $125 million to $140 million from 2022 through 2024 to maintain and improve the integrity of the existing DEF generation fleet.

Consistent with the 2021 Settlement Agreement, DEF placed in service eight solar sites during 2022 and 2023, resulting in 600 MWs of additional solar generation, bringing DEF's solar capacity to 1,170 MWs.

In addition to the increased generation provided by the new solar sites, DEF completed a heat rate improvement project at the Osprey plant, which involved installing an innovative technology combustion system and increasing unit capacity by approximately 55 MWs, bringing the Osprey plant's total output to approximately 625 MWs.

IV. <u>DeBary Hydrogen Project</u>

Q. Please provide a brief overview of the DeBary Hydrogen Project.

A. The Commission approved the Vision Florida Program in the 2021 Settlement Agreement.[3] One of the projects DEF pursued as part of the Vision Florida Program is the DeBary Hydrogen Project. The DeBary Hydrogen Project is an innovative, clean energy hydrogen production and storage system that will be used to produce hydrogen under numerous real and simulated conditions, including solar following simulated future grid conditions and grid voltage support.

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[3] The 2021 Settlement Agreement authorized the Company to pursue pilot projects through the Vision Florida Program. The Vision Florida Program is discussed in greater detail in the direct testimonies of Company witnesses Brian Lloyd and Hans Jacob. My testimony is focused on the DeBary Hydrogen Project, which is a part of Vision Florida.

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The project consists of two (2) 1 MW Polymer Electrolyte Membrane electrolyzers and incorporates the existing 74.5 MW DeBary Solar Plant to provide clean energy for the electrolyzer units that will separate water molecules into oxygen and hydrogen atoms, generating truly green hydrogen. The resulting oxygen will be released into the atmosphere, while the hydrogen will be delivered to reinforced containers for safe storage. The system will ultimately deliver the stored hydrogen to a CT that has the ability to run on blended fuel as well as 100% hydrogen. In addition to the DeBary Solar Plant, the project site also includes peaking gas CTs that will allow the Company to provide additional power to accommodate changes in demand and technological growth. The DeBary Solar Plant is an ideal location for the DeBary Hydrogen Project because it has diverse generation sources available to power the electrolyzers.

Q. What is the estimated project cost and projected in-service date for the Debary Hydrogen Project?

A. The estimated project cost included in this filing is $25 million, and the projected in-service date for the DeBary Hydrogen Project is Q4 2024.

Q. How does the Debary Hydrogen Project benefit customers?

A. The DeBary Hydrogen Project is one example of how DEF is maximizing customer benefits while providing technological and geographic diversity through state-of-the-art technology that will help DEF transition to cleaner energy. The Debary Hydrogen Project will benefit customers through the early demonstration of an integrated technology capable of providing increased energy storage, fuel agility, and grid reliability. In addition, this project will allow DEF to gain valuable learnings in the following areas:

- Determining the variable cost of hydrogen production, resulting energy production, and how hydrogen best complements increased renewable energy growth.
- Procedures for integrated operation and control, material selection, safety, emissions, operation, and maintenance.
- Assistance with future designs and scale-up evaluations, which will help guide DEF's continued transition to renewable energy.

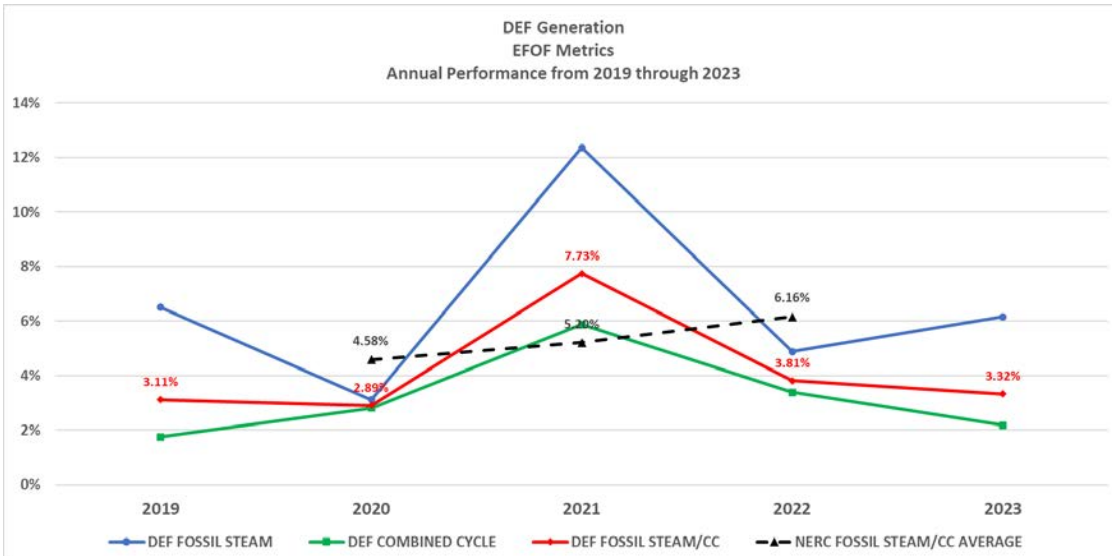
V. Reliability

Q. How does DEF measure and evaluate the reliability of its steam and combined cycle units?

A. DEF evaluates the reliability, or the operating performance, of its generation fleet by comparing the Equivalent Forced Outage Factor ("EFOF") for the Company's steam and combined cycle units with EFOF data reported for the North American Electric Reliability Corporation ("NAERC") steam and combined cycle units over the same period.[4] A generating unit's EFOF is equal to the hours of unit forced unavailability (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of service, plus the unavailability of that unit (unplanned outage, unplanned derate, and service hours). The chart below

[4] NAERC EFOF data is available beginning in 2020. Prior to 2020, NAERC tracked the Equivalent Forced Outage Rate ("EFOR"). DEF anticipates that 2023 data will be available mid-2024.

provides a summary of DEF's steam and combined cycle performance for the previous five years. As the chart demonstrates, the operating performance for DEF's generation fleet has improved over the last three years and is outperforming the NAERC average.



Q. Does the Company use EFOF to measure reliability at its simple cycle generating units?

A. No, the Company utilizes starting reliability as a more informative metric to measure the reliability of its simple cycle fleet. Starting reliability is the ratio of successful startups to attempted startups. A startup is successful if the unit synchronizes to the grid within a certain, pre-defined time limit. If the unit is unable to start — a "failed start" — or the startup is delayed, it would fail in its peaking duty. Therefore, a high starting reliability is desirable. DEF's simple cycle fleet has consistently averaged over 99% starting reliability each year. For example, of 2,124 starts in 2023, DEF only had 11 failed starts, resulting in a starting reliability of 99.48%.

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Q. How does DEF measure reliability for its solar generating facilities?

A. For solar generating facilities, the Company uses energy yield and inverter availability to measure reliability. Energy yield is the percentage of energy produced as compared to the maximum energy that could have been produced, considering the actual available solar conditions (daylight hours, sun position, degree of cloudiness, etc.). Inverter availability is the proportion of time that a system is in an operable and usable state over a specified period that includes any necessary corrective maintenance, preventative maintenance, or any other downtime required for the system to remain operable.

Q. How reliable are DEF's solar facilities?

A. In 2023, DEF's solar facilities operated with an average net capacity factor of 27%.[5] Typical solar facilities have a net capacity factor of 23-25%.[6] DEF's solar facilities provide approximately 6% of DEF's total generation.

Q. How do DEF's reliability metrics translate into benefits for customers?

A. DEF's positive operating and reliability metrics translate into better reliability for customers and provide an opportunity for the Company's most efficient operating units to minimize fuel costs. These positive metrics also increase the probability

[5] Adjusted to exclude events outside management control ("OMC").
[6] *See* U.S. Energy Information Administration, *Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels*, (Last visited: Feb. 7, 2024), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b (showing the average capacity for photovoltaic solar in 2022 to be 24.4%).

C2-676

that generation is available during times of lower customer demand to enter the off-system sales market and further offset customer fuel costs.

VI. Performance and Safety

Q. Has the Company achieved and sustained a favorable safety record while improving performance over the past five years?

A. Yes. Safety is the highest priority in every task that the Company performs and is an integral part of our daily decision-making process. Duke Energy is committed to a healthy and injury-free workplace and is committed to the safety of our employees, families, customers, contractors, visitors, and the communities in which we operate. Duke Energy's focus on safety has resulted in consistently outstanding performance in this area over the past several years, with Duke Energy's Generating Fleet attaining industry top decile results for five consecutive years. The table below shows the total incident case rate ("TICR") specifically for DEF's Generating Fleet. TICR is the number of work-related injuries per total number of work hours in a year; the result is a percentage that reflects the frequency of injuries. A TICR less than 0.5 is considered top decile performance in the industry, and DEF's TICR has been below that threshold since 2018.

Year	Recordables	Work Hours	TICR
2018	16	10,566,766	0.30
2019	17	10,126,610	0.34
2020	17	9,698,928	0.35
2021	14	9,442,310	0.30
2022	18	9,722,439	0.37
2023	23	10,605,610	0.43
Grand Total	**123**	**70,365,684**	**0.35**

C2-677

Q. How does DEF measure the operating performance of its generation fleet?

A. In addition to EFOF, discussed above, DEF measures the operating performance and efficiency of its fleet through the "heat rate" – or the measurement of the amount of fuel used to produce a kilowatt hour ("kWh") of power. Heat rate is expressed as a British Thermal Unit ("BTU") per kWh. The lower the fleet's heat rate, the more efficient it is because it requires less fuel to generate the same amount of power.

Q. Has the Company undertaken initiatives to improve the operating performance of its generation fleet?

A. Yes, the Company has undertaken several initiatives to improve the generation fleet's performance. First, DEF's Power Generation organization has embarked on a generation fleet heat rate and capacity initiative that is focused on reducing the generation fleet's operating fuel costs through greater fuel efficiency. Second, by adopting new technologies, DEF's combined cycle units are capable of being more flexible as solar generation is developed and added within DEF's service territory. Third, DEF is installing newer, more efficient combustion turbine hardware systems at the Hine Energy Complex, Tiger Bay, Bartow, and Citrus CC plants.

Q. Please describe some of the benefits of DEF's heat rate and capacity initiatives.

A. DEF's heat rate improvement project will integrate some of the newest combustion technology into DEF's combined cycle units and will increase overall system capacity by 428 MWs after all projects are completed in 2026. Once completed, these projects, along with increased generation, will reduce fuel costs to customers by an estimated $150 to $200 million dollars per year due to an increase in reliability ramp rates and low load operations, which I discuss below. These uprate improvement projects are planned for the eligible units during the unit's next routine maintenance outage cycle, which will allow for long lead time equipment to be manufactured and delivered and will reduce the need for out of cycle maintenance outages. Exhibit RDA-3 summarizes the CC units that are part of the heat rate improvement project and their corresponding heat rate improvements.

Q. Please explain how making combined cycle units more flexible as solar generation is added to the electric grid improves the generation fleet's performance.

A. As additional solar generation is developed and added within DEF's service territory, DEF's combined cycle units must become more flexible because solar energy is intermittent due to variables such as the time of day and the weather, and these variables contribute to the unpredictability and variation of solar generation. The unpredictability of solar impacts grid frequency and voltage, which may result in the electric grid becoming unstable due to an erratic energy supply, which in turn, could cause equipment damage, interruptions, and power outages. Therefore, as solar generation continues to be added to the electric grid, the Company's generating units need to be increasingly agile in responding to load changes.

For example, since cloud coverage can cause rapid changes to the energy output of solar generation, online steam and CC operating plants need to be able to adapt quickly and adjust output to maintain reliability and grid stability, DEF has implemented an innovative combustion technology at the Osprey plant that allows the units to operate at lower loads and use faster ramp rates, all while complying with environmental regulations.

Q. What is low load operation and how does it benefit DEF's customers?

A. Low load operation is the ability to keep affected units online during periods of lower system demand that would normally require units to be removed from service. Improving low load capability, or turndown, allows DEF to reduce unit cycles on its CTs, thereby reducing costs and reducing the impact on equipment life. Since low load operations are restricted by environmental compliance regulations and rules, improving a unit's low load operation enables DEF to keep its most efficient units online to serve our customers.

Cycling a unit on and off also adds to the cost of operation. A unit cycle removes what we call "parts life" from the unit, so fewer cycles on a unit results in lower operating costs, and a reduction in maintenance cycle costs that otherwise would be borne by DEF's customers.

Q. Has the generating efficiency of DEF's generation fleet improved over time?

A. Yes. The efficiency of DEF's generation fleet has improved over time, due primarily to three factors: heat rate improvements, the retirement of less efficient units, and employing economic dispatch. I previously discussed DEF's heat rate improvement project and how these improvements will (in addition to increasing capacity) improve reliability ramp rates and low load operations, thereby reducing fuel costs. With the introduction of new heat rate improvement technology, DEF expects that the fleet's heat rate will be reduced by an additional 1,000 BTU by the end of 2026—an estimated one to two percent improvement. As shown in Exhibit RDA-3, the heat rate of DEF's generation fleet has continued to improve since 2018.

Second, and also since 2018, DEF has retired some higher heat rate coal units and improved the efficiency of its gas units. And third, DEF (and Duke Energy's entire generation fleet) uses economic dispatch to reduce the operating heat rate of the generation fleet. Economic dispatch is a continuous and dynamic process that Duke Energy uses to create the most economical power on the grid. This process allows the entire enterprise to deliver the lowest cost source of electric generation to the grid by dispatching units with the lowest costs before calling upon less efficient units that result in higher fuel costs. Combined with the heat rate improvements and the use of innovative technologies, power will be dispatched utilizing more accurate inputs for economic dispatch, allowing DEF's most efficient units to be the first to respond to load demand.

C2-681

Q. How do DEF customers benefit from a positive operating performance of DEF's generation fleet?

A. Positive fleet operating performance minimizes forced and unplanned outages and results in lower electric bills. Since fuel costs are passed on to customers as part of their total electric bill, customers benefit from positive operating performance when the most efficient units remain online and are dispatched first. By utilizing economic dispatch, DEF is ensuring that it is delivering the lowest cost power to the grid, and that it only calls upon less efficient (and more costly) units as demand increases.

Q. Has the positive operating performance of the Company's generation fleet impacted O&M costs?

A. Yes. Using the economic dispatch model for unit loading and normal operations provides DEF a tool for maintaining, or even reducing, variable O&M costs that are associated with more reliable and efficient units. From time to time, DEF relies on purchased power when reserves are insufficient to serve the system load. Purchasing power at an equal to or lower cost than the Company can generate based on market conditions allows older, less efficient units to be called upon less frequently, thereby reducing maintenance and startup costs.

VII. DEF Generation Non-Fuel O&M and Capex

Q. What is the budget and approval process for the non-fuel O&M and Capex for DEF's generation fleet?

A. Long-range planning for DEF's Power Generation organization is a structured process that balances risk with financial constraints that consists of five (5) years of projected capital and outage O&M costs for maintenance projects at DEF's generation stations. Station and subject matter experts identify projects for future years and group them among the following categories:

- Regulatory requirements
- Safety and environmental risks
- Long-term service agreements
- Growth and strategic initiatives
- Optimized routine reliability maintenance
- Economical reliability maintenance
- Facility infrastructure needs

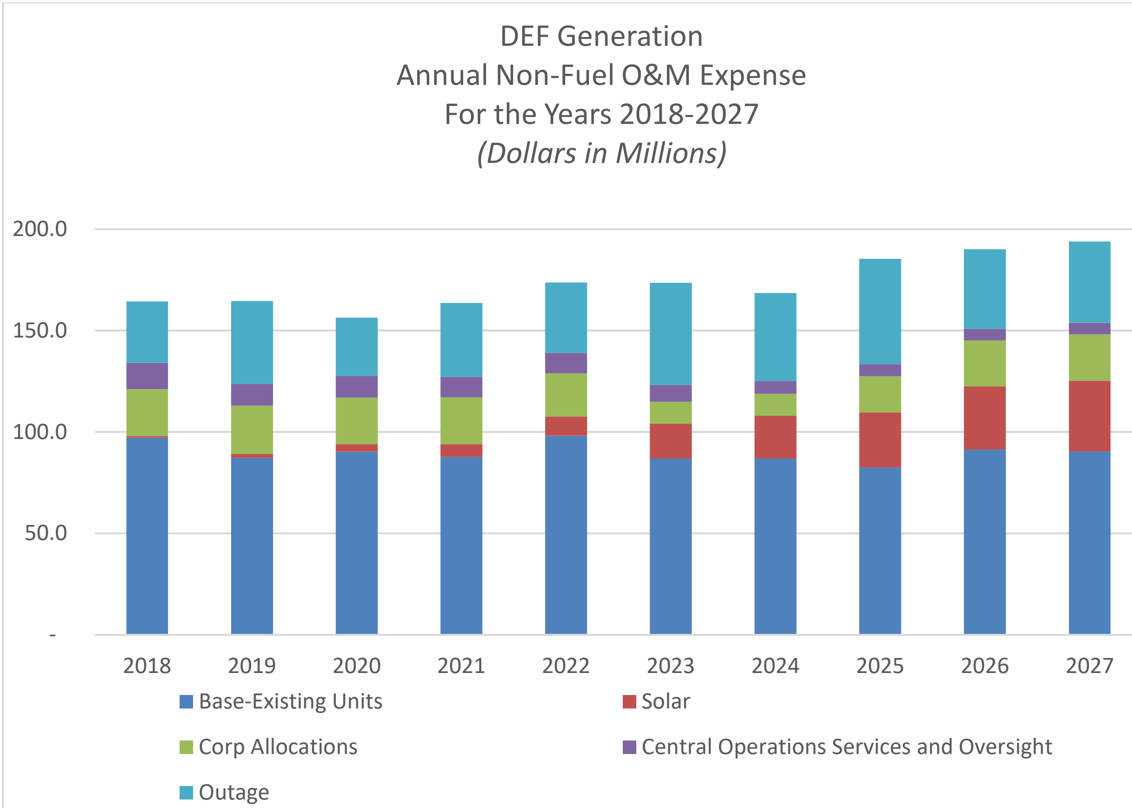
DEF evaluates and prioritizes capital and outage O&M projects according to fleet procedures, which include condition-based equipment inspections. This process allows DEF to invest Capex and O&M in the fleet's most efficient and responsive units first, thereby prioritizing the needs of the remaining units as Capex and O&M is available and resulted in the Company identifying several power generation projects to include in the 2025, 2026, and 2027 test years.

Q. Please describe the non-fuel O&M performance experience of DEF's generation fleet.

A. The transformation of DEF's generation fleet has been underway since 2016. During this time, DEF has invested in technology and facility upgrades, and undertaken strategic unit and station retirements. This effort focuses on maintaining and minimizing fuel and non-fuel costs. As shown in the chart below, DEF's non-fuel costs attributable to base operations for existing generating units (the dark blue bar) have remained fairly constant and have even decreased for several years over a ten (10) year period. In fact, the forecasted amount for non-fuel costs for 2027 is less than the comparable actual amount in 2018.

Outage O&M (the light blue bar) exhibits slight fluctuations over the years due to equipment run-times but generally has held constant despite increasing fleet capacity and maturing generating sites. As expected, the addition of new generation facilities, including the Citrus CC, the Osprey Energy Center, and the addition of thirty-four (34) new major solar sites since 2018, has added incrementally to non-fuel O&M costs. However, it is important to note that despite the addition of considerable new generating capacity since 2016, the Company has been able to safely and reliably operate and maintain its fleet with fewer resources.

C2-684



Q. Please differentiate between the two primary O&M cost categories – Base Existing Units and Outage as shown in the chart above.

A. Base Existing Unit costs include costs associated with day-to-day routine activities and basic utility services. Some examples of these costs include labor (straight time and overtime), materials required for routine activities, outside contracting services, and environmental permits. Outage costs include all major maintenance activities and non-routine activities that improve a unit's operating reliability or efficiency. Examples of Outage costs include CT major maintenance, steam turbine outage work, generator major maintenance work, and other similar projects.

While Base Existing Unit costs have declined over the 2018-2027 period as the generation fleet has transformed into a cleaner, more efficient portfolio and as the Company has implemented improvements, Outage costs have fluctuated based on major equipment maintenance requirements, which are in turn driven by hours of operation. With major maintenance requirements driven by usage-based metrics, outage budgets experience more variation than base budgets.

Q. Has the Company taken steps to reduce fossil fleet O&M and Capex associated with operating and maintaining DEF's generation fleet?

A. Yes. DEF continually works to reduce costs for both O&M and Capex, and the Company has implemented various initiatives to reduce costs through efficiencies in business transformation and planning. For example, the Business Transformation effort is intended to identify where process and financial efficiencies can be realized within DEF Generation. These changes are intended to be long-term to achieve sustainable cost savings. In addition, DEF employees are encouraged to find new ways to work more efficiently and reduce costs. Ideas are solicited from every individual in the company to consider day-to-day activities and determine if there are opportunities to make our business more efficient resulting in sustainable cost savings.

Q. Please summarize the generation fleet's capital requests for the years 2025-2027 that are included in the MFRs.

A. Please refer to Exhibit RDA-4 attached to my testimony. This exhibit summarizes the major maintenance projects (grouped by similar work scopes) and associated budget costs included in DEF's rate case for each of the three test period years.

Q. Please briefly describe the Commission's "O&M Benchmark Test" and how the requested test year O&M for DEF Generation compares to the Benchmark O&M.

A. The Commission's O&M benchmark test originated in the early 1980's as a metric used by the Commission and its staff to evaluate the reasonableness and prudency of a company's request for O&M in its test year cost of service. The Commission's O&M Benchmark Test escalates the O&M by function approved in a company's last rate proceeding by the consumer price index and customer growth for those O&M functions whose costs are impacted by customer growth. The resulting, escalated O&M is then compared to the test year O&M requested by a company. If the test year O&M exceeds the Benchmark O&M, the company is required to provide justification for the increase in order to obtain recovery of its requested O&M amount. If the company's test year O&M is less than the Benchmark O&M, the company has met the reasonableness test for the O&M to be approved.

Please refer to MFR Schedule C-41, which shows the Commission's O&M Benchmark analysis for test years 2025, 2026, and 2027, and the DEF's justification statement for test year O&M that exceeds the benchmark amount. For example, in the calendar year 2025, Steam Production O&M exceeds the

Benchmark O&M by $2.9 million. However, the test year O&M for Other Power Production is $7.9 million less than the Benchmark O&M, resulting in an O&M amount of approximately $5.0 million less than the Benchmark Test for the two functions I oversee. In addition, I note that DEF's requested test year O&M for the years 2026 and 2027 are less than their respective benchmark amounts by $4.4 million and $4.5 million, respectively. This analysis provides a quantified demonstration of the efforts DEF has employed to control and reduce Generation O&M costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Nicole Aquilina was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC

Docket No. 20240025-EI
Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

NICOLE AQUILINA

On Behalf of Duke Energy Florida, LLC

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole Aquilina. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Accounting Manager II, providing accounting leadership for Duke Energy Florida, LLC ("DEF" or the "Company"). DEF is a subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Please summarize your education and professional qualifications.

A. I graduated from The College of New Jersey with a Bachelor of Science in Finance. I have 16 years of professional experience in various accounting roles. Nine of those years have been with Duke Energy. I was named to my current position at DEF as Accounting Manager II in May 2023. Prior to that, I was the Accounting Manager II of Gas Utilities and Infrastructure, which included Duke Energy Ohio Gas, Duke Energy Kentucky Gas, and Piedmont Natural Gas.

Q. Please briefly describe your duties as Accounting Manager II.

A. I am responsible for ensuring that the accounting impacts of the Company's business activities and transactions are understood and properly recorded to the general ledger, and that such accounting impacts, as well as any applicable related variances to budget and prior year results, are clearly explained and properly presented in internal and external financial reports. I am also responsible for ensuring that the accounting team performs its tasks in an accurate and timely manner in accordance with published deadlines while strictly adhering to Company policies and controls.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and support accounting issues in this rate case. I also explain why DEF is not submitting a nuclear decommissioning study. In addition, I address components of the Company's dismantlement study. Finally, I address the Company's pension settlement deferral that was initially requested in the 2017 Settlement.[1]

Q. Have you prepared any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of Exhibit NA-1, which is a list of the MFRs I sponsor or co-sponsor in this rate proceeding. I also sponsor sections 1 through 6 of the fossil dismantlement study, which is included as Exhibit JTK-2 to witness Jeffrey Kopp's testimony. These exhibits are true and accurate, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. First, I address various accounting matters related to this rate request, including the Company's books, the general ledger, historical year, and exhibits. Second, I explain why no nuclear decommissioning study is being filed and no accrual is being requested. Third,

[1] Approved in Order No. 2017-0451-AS-EU.

I address the Dismantlement Study, which was prepared by witness Jeffrey Kopp of 1898 & Co., part of Burns & McDonnell Engineering Company, Inc. Finally, I address the Company's Pension Accounting and Pension Settlement Charges Regulatory Asset, which was initially deferred during the Company's 2017 Settlement, and the amount of amortization included in the 2025, 2026, and 2027 test years for this asset. The Company is requesting approval to continue deferring and amortizing future pension settlement charges in this rate case filing.

II. DEF'S ACCOUNTING BOOKS

Q. What is DEF's financial position at December 31, 2023?

A. The Company's financial position and operating results for the twelve months ending December 31, 2023 (the "Historical Year") are set forth in MFR Schedules B-3 and C-6.

Q. Are you familiar with the accounting procedures and books of account of DEF?

A. Yes. The books of account of DEF follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"). This Uniform System of Accounts has been adopted by the Florida Public Service Commission ("FPSC" or "Commission") and is followed by the investor-owned utilities subject to the Commission's jurisdiction.

Q. What steps does the Company take to ensure that its books and records are accurate and complete?

A. DEF maintains and relies upon an extensive system of internal accounting controls and audits by both internal and external auditors. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.

The system of internal accounting controls is reviewed annually, tested, and documented by the Company to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that the Company's financial statements are materially accurate.

Q. Do the Company's MFRs accurately reflect the books and records of the Company?

A. Yes, the historical information provided in the MFRs was obtained from the Company's official books and records and is therefore subject to the accounting controls I explain above.

III. <u>NUCLEAR DECOMMISSIONING</u>

Q. WHAT AMOUNT OF NUCLEAR DECOMMISSIONING EXPENSE IS INCLUDED IN DEF'S PER BOOKS AMOUNT FOR DEPRECIATION EXPENSE?

A. Currently, DEF is not collecting any funds from Florida customers for decommissioning of the retired Crystal River Unit 3 nuclear power station and therefore, the per books amount of nuclear decommissioning expense included in DEF's cost of service is $0 in the test years. The Commission, in its order approving the transaction between DEF and Accelerated Decommissioning Partners ("ADP") in Docket No. 20190140-EI, held that future filings of decommissioning studies required in Rule 25-6.04365(3), F.A.C., are unnecessary and shall be waived. Accordingly, DEF has not submitted a decommissioning study in this filing.

IV. <u>DISMANTLEMENT STUDY</u>

Q. Did the Company prepare a dismantlement study?

A. The Company's 2023 Final Dismantlement Cost Study was prepared by witness Jeffrey Kopp and is included as Exhibit JTK-2 to his testimony. This study reviews the Company's fossil fuel and power generation facilities and provides a recommendation regarding the total cost to dismantle those facilities at the end of their useful lives. Mr. Kopp sponsors Section 7 of the 2023 Final Dismantlement Cost Study, while I support the information provided in Sections 1 through 6 of the study. Based on the 2023 Final Dismantlement Cost Study, the fossil dismantlement annual accrual for the 2025, 2026, and 2027 test years is $37.1 million (system). A detailed calculation of the accrual included in the test year, along with the other information required by the Commission's fossil dismantlement rule, is provided in Exhibit JTK-2.

V. <u>PENSION ACCOUNTING AND PENSION SETTLEMENT</u>

Q. What pension plans do DEF employees participate in, and what benefits do they receive?

A. DEF employees not covered by a collective bargaining agreement participated in the Progress Energy Pension Plan ("PEPP") until December 31, 2015. Effective December 31, 2015, the PEPP was merged into the Duke Energy Retirement Cash Balance Plan ("RCBP"). DEF employees covered by a collective bargaining agreement participated in the Retirement Plan for Bargaining Unit Employees of Florida Progress Corporation. Effective December 31, 2020, a portion of the Retirement Plan for Bargaining Unit Employees of Florida Progress Corporation was merged into the RCBP, and the remaining portion was merged into the Duke Energy Legacy Pension Plan ("DELPP").

The RCBP and DELPP use a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits and interest credits. Effective January 1, 2014, a former PEPP participant's cash balance account consists of two subaccounts: (1) a cash balance subaccount attributable to pay credits earned prior to December 31, 2013, which increases with interest credits on an annual basis, and (2) a subaccount established January 1, 2014, for future pay and interest credits that are applied on a monthly basis. The pay credit is determined by points, with a participant's points equal to the sum of attained age and benefit service as of January 1 of each calendar year. Provisions applicable to employees participating in the Retirement Plan for Bargaining Unit Employees of Florida Progress Corporation are based on a final average pay formula, or cash balance formula, depending on the date of original hire. Final average pay formula participants were hired prior to January 1, 2003. Cash balance formula participants were hired after December 31, 2002.

Q. What are the components of net periodic pension costs under Generally Accepted Accounting Principles ("GAAP")?

A. Net periodic pension cost is the amount recognized in an employer's financial statements as the cost of a pension plan for a period. The term net periodic pension cost is used instead of net pension expense because the service cost component recognized in a period may be capitalized as part of an asset such as inventory. Components of net periodic pension cost under Accounting Standards Codification ("ASC") 715 are:

Service cost. Service cost is the actuarial present value of benefits attributed by the plan's benefit formula to services rendered by employees during the period.

Interest cost. Interest cost is the increase in projected benefit obligation due to passage of time.

Expected return on plan assets. The expected return on plan assets is calculated by applying the expected rate of return on plan assets to the beginning of year amount of plan assets.

Gain or loss amortization. Gains and losses are changes in the amount of projected benefit obligations or plan assets due to actual experience that is different than assumed experience, as well as changes in assumptions, such as the discount rate applied to future cash flows expected to satisfy the pension obligation. Amortization expense is included in net periodic pension cost when beginning of year unrecognized gain or loss exceeds a "corridor" of ten percent of the greater of the projected benefit obligation or the market-related value of plan assets. Amounts in excess of the corridor are amortized over the average remaining future service of active plan participants, or average remaining life expectancy for plans, where almost all (more than 90%) of the plan participants are inactive.

Prior service cost or credit. Prior service cost or credit represents the cost of retroactive benefits granted in a plan amendment that increase or decrease the projected benefit obligation. Amounts are amortized over the average remaining

C3-704

future service of active plan participants, or average remaining life expectancy for plans, where almost all (more than 90%) of the plan participants are inactive.

Q. For pension accounting purposes, what is a settlement?

A. A settlement is defined as an irrevocable transaction that relieves an employer of primary responsibility for benefit obligations under a benefit plan and eliminates significant risks related to the obligation and assets used to affect the settlement. Examples of settlement transactions include making lump-sum cash payments to plan participants in exchange for their rights to receive their pension benefit, assumption of the benefit obligation by a buyer as part of a business combination, and the purchase of nonparticipating annuity contracts to cover participants' vested benefits.

Q. What is settlement accounting?

A. Settlement accounting triggers recognition in earnings of gains or losses from settlements equal to the percentage of the settled obligations when the cost of all settlements during a year is greater than the sum of the service cost and interest cost components of net periodic pension cost for the pension plan for the year. In other words, rather than amortizing a portion of the gains and losses that have been deferred in a regulatory asset account for future inclusion over time, GAAP, which governs pension accounting, requires the inclusion of these costs to be accelerated and charged all at once.

Q. Please describe DEF's pension settlement.

A. ASC 715 provides that if lump sum benefit payments to pension plan participants in a calendar year are more than the sum of the pension plan's service cost and interest cost, then a company must record a pension settlement charge, which represents the accelerated recognition of a portion of the unrecognized actuarial pension gain or loss, in proportion to the amount of pension obligation settled.

Pension settlement accounting was triggered in 2019 and 2022 for a Duke Energy sponsored pension plan in which DEF employees participate. DEF deferred the retail portions of the 2019 and 2022 settlement charges as a regulatory asset (account 0182334) and began amortizing them immediately to account 0926999 over approximately 10 years.

Q. Has DEF entered into a recent settlement agreement that addresses this settlement treatment?

A. Yes. The 2021 Settlement agreement[2] permits DEF to continue deferral of the impact of pension settlement accounting to a regulatory asset with the amortization period to be determined in the next general base rate case proceeding.[3]

Q. Are amortization amounts included in the 2025, 2026, and 2027 test years?

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[2] Approved in Order No. 2021-0202-AS-EI

[3] It should be noted that although DEF's 2017 and 2021 settlements provide for amortization to begin with the next rate case, DEF has chosen to begin amortizing the deferral immediately over the remaining service life of pension plan participants.

A. Yes. The amount of amortization of Pension Settlement Charges are as follows:

Year		System Settlement Charge	System Projected Amortizaton** 2025	2026	2027
2022*	Actual	12,390,048	1,292,842	1,292,842	1,292,842
2023	Projected	5,476,511	595,927	595,927	595,927
2024	Projected	-			
2025	Projected	5,277,495	248,419	589,268	589,268
2026	Projected	5,024,892		238,367	568,427
2027	Projected	4,445,702			212,778
Total		32,614,648	**2,137,188**	**2,716,404**	**3,259,242**

* Cumulative Settlement Charges as of 12/31/2022
** Amortization period is the estimated remaining life of plan participants, 9 years.

Q. What is the Company seeking in this base rate case with regards to the pension settlement agreement?

A. In this rate case, the Company is seeking approval to continue deferring and amortizing any future pension settlement charges.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Benjamin M.H. Borsch was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Duke Energy Florida, LLC

Docket No. 20240025-EI
Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

BENJAMIN M. H. BORSCH

On behalf of Duke Energy Florida, LLC

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Benjamin M. H. Borsch. My business address is Duke Energy Florida, LLC, 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or "the Company") as Managing Director of Integrated Resource Planning and Analytics.

Q. What are the duties and responsibilities of your position with DEF?

A. I am responsible for directing the resource planning process for DEF in an integrated approach in order to find the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. In this capacity, I oversee numerous studies to evaluate the system impact and cost effectiveness of various proposed and alternative generation projects. I oversee the completion of the Company's Ten-Year Site Plan ("TYSP") filed each April.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science and Engineering degree in Chemical Engineering from Princeton University. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009, I became Manager of Generation Resource Planning for Progress

Energy Florida, and following the 2012 merger with Duke Energy Corporation, I accepted my current position. Prior to joining Progress Energy, I was employed for more than five years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas-fired power plant projects in nine states. I was also employed for more than eight years as an environmental consultant with projects including development, permitting, and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

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

A. Yes. I provided testimony in several proceedings, including Docket No. 20200176-EI, Petition for a Limited Proceeding to Approve Clean Energy Connection Program and Tariff and Stipulation and Docket No. 20170260-EI, DEF's Petition for a Limited Proceeding to Approve First Solar Base Rate Adjustment.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe the Company's plan to add new and upgraded resources to the DEF portfolio, bringing clean energy and system benefits to DEF's customers. I will also discuss the load forecast used in the preparation of this rate case. As I use the term "load forecast" in my testimony, it means the

Company's individual projections of customers, energy sales, and coincident peak demand. I discuss the results of the resource planning analyses and how they support the cost effectiveness, prudence, and need for additional solar, energy storage, and combined cycle efficiency improvement projects that I discuss further in my testimony. Finally, I explain why the Levy County land is being included in Plant Held for Future Use in this case.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of several exhibits, as follows:

- Exhibit BMHB-l, a list of the Minimum Filing Requirements ("MFRs") schedules I sponsor or co-sponsor;
- Exhibit BMHB-2, Historic and Projected Customer, Energy Sales & Seasonal Demand Forecast;
- Exhibit BMHB-3, Solar Cost Analysis;
- Exhibit BMHB-4, CEC Expansion Cost Analysis;
- Exhibit BMHB-5, Combined Cycle Efficiency Improvements Project Cost Analysis; and
- Exhibit BMHB-6, Battery Storage Cost Analysis.

These exhibits are true and accurate, subject to being updated throughout the course of this proceeding.

Q. Do you sponsor any schedules of the Company's MFRs?

A. Yes, I sponsor in full or co-sponsor portions of the schedules listed in Exhibit BMHB-1. These MFR Schedules are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. My testimony presents the value of the DEF's planned investments in additional solar generation, efficiency improvements to its existing combined cycle fleet, and new battery energy storage. In support of the Company's evaluation of this value, I present the planning processes underpinning DEF's Integrated Resource Plan ("IRP"), discussing the design and selection of the Company's resource portfolio, proposed generation facilities and renewable energy programs, and the load forecast and methodology. The IRP is a critical component of our strategy, designed to identify the most cost-effective mix of resources to meet future demand and energy needs. It emphasizes fuel diversity, fuel supply risk management, and the cost-effectiveness of various projects.

The cost-effectiveness of these proposed solar projects, combined cycle efficiency improvement projects, and battery energy storage is a key focus of my testimony. The Company is proposing approximately 1,050 MW of solar photovoltaic ("PV") generation, 100 MW of battery energy storage, and efficiency improvements to existing natural gas-fired combined cycle facilities. These additions are strategic

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moves to replace retiring coal units and enhance our resource plan with cost-effective, supply-side resource alternatives. I highlight the expected savings for customers, the natural hedge against fuel price volatility provided by solar resources, and the anticipated rate impacts. These projects are not just about increasing DEF's generation capacity; they represent our commitment to providing reliable power while reducing fuel consumption.

Load forecasting is the backbone of our planning and budget processes. I outline the purpose, methodology, and major assumptions behind DEF's load forecast, which anticipates slower retail sales and peak demand growth as the increased customer base is offset by energy efficiency and rooftop solar penetration.

Additionally, I discuss the expansion of the Clean Energy Connection ("CEC") program, justified by additional demand from customers, with five of the proposed solar projects made available to subscribing customers under this program. Finally, I touch upon the inclusion of Levy County land in the rate base as Plant Held for Future Use. This strategic decision underscores the potential for future generation or transmission projects on this property.

In order to meet the future demand and energy needs of its customers, the Company proposes to further develop its resource portfolio by building renewable generation, expanding its community solar program, conducting efficiency improvements at

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existing combined cycle facilities, and adding additional battery storage projects. My testimony discusses the load forecast methodology used to determine those demand and energy needs, identifying key assumptions underlying the forecast and explaining the differences in processes between different classes of customers.

In conclusion, my testimony supports DEF's petition for a rate increase by detailing the planned resource additions and their benefits, demonstrating the cost-effectiveness of these projects, and explaining the underlying load forecast and economic assumptions. Our goal is to bring clean energy and system benefits to DEF's customers, and this petition represents a significant step towards achieving that objective.

Q. How does your testimony relate to the testimony of other DEF witnesses?

A. DEF witness Vanessa Goff explains the details of the portfolio of 14 solar projects that are underway as a part of the plan to build future solar and bring clean energy and fuel and operational benefits to DEF's customers. She will describe the specifics of the selection, construction, and costs of these projects being added to the existing DEF solar generation portfolio.

DEF witness Reginald Anderson describes the details of the combined cycle efficiency projects currently underway across DEF's existing fleet of natural gas fired combined cycle generating units. As the name suggests, these projects will bring greater efficiency to the upgraded units and fuel savings to DEF's customers.

DEF witness Hans Jacob describes the details of DEF's Powerline battery project.

DEF witness Marcia Olivier explains how the load forecast is used to develop the Company's revenue forecast. She also explains the financial aspects of DEF's proposed expansion of the Clean Energy Connection program.

II. <u>INTEGRATED RESOURCE PLAN PORTFOLIO</u>

Q. How does DEF determine its future demand and energy needs and how best to meet those needs?

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

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

Q. What are the reliability standards the Company used to design its resource portfolio and determine the need for additional resources?

A. 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. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF plans its resources to satisfy a minimum 20% Reserve Margin criterion and a maximum of one day in ten years loss of load probability. DEF has used this dual reliability criteria in its IRP process since the early 1990s. DEF's resource plans, based on these dual-reliability criteria, have been reviewed by the Commission each year since the early 1990s in the annual TYSP.

DEF's resource portfolio is designed to satisfy the 20% Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have

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sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20% Reserve Margin thresholds before LOLP becomes a factor.

Q. Are there other criteria for selecting new resources?

A. DEF considers a variety of criteria in selecting the final plan. One key factor is fuel diversity and the attendant risk of fuel volatility. Over 75% of energy on the DEF system currently comes from natural gas. As DEF projects forward to the eventual retirement of the remaining coal units, this value would rise absent other options. That would present increasing risk around natural gas cost volatility to DEF's customers. DEF places a qualitative value on energy from other fuel sources, such as solar, that provide a natural hedge against gas prices. A second factor is fuel supply risk. DEF recognizes that there is significant pressure on the coal mining industry as well as the associated transportation channels. As a result, DEF recognizes that in the longer term, reliance on coal as a firm fuel source may be increasingly risky. In the case of solar, the proposed projects are selected in the IRP optimization process. DEF does, however, adjust the dates of these projects to smooth the rate of build and allow for a more efficient and effective development process. Some projects have been brought forward in time to create a continuity in project development, to allow DEF to build a portfolio of project options that will have the best available land options and interconnection positions. DEF seeks to optimize the timing of these projects considering issues such as equipment procurement, labor availability, and interconnection timing.

Q. How has the Company's emissions profile changed over time, given its process for considering and adding generation resources?

A. DEF has been moving to a cleaner generating fleet by investing in modernizing its existing fleet, as well as planning new resources for system efficiency. This has allowed DEF to reduce SO_2 and NO_X pollutants by over 97% and 81%, respectively, since 2005. Since 2005, DEF has reduced CO_2 emissions by about 25%.

Q. How was the Company's base case fuel price forecast developed?

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

Q. What resource additions is DEF proposing that impact the test year periods for this rate case?

A. DEF's planned supply resource additions and changes relevant to this rate case include solar energy plants, a battery energy storage project, and heat rate improvements to several existing natural gas fired combined cycle facilities.

DEF's primary resource addition proposed for the period 2025-2027 is the addition of approximately 1,050 MW of solar PV generation with an expected equivalent summer firm capacity contribution of approximately 262 MW. The details of these solar additions are discussed in more detail in witness Vanessa Goff's testimony, as well as in a later section of my testimony.

DEF will complement the solar portfolio with 100 MW of battery storage available in 2027. This battery storage will provide valuable capacity in peak generation periods, will allow storage for energy generated during lower cost times of day that can be released during higher cost periods, and will provide a nearly instant response resource that can operate to smooth the impact of sub-hourly solar generation variability. Additional details regarding the battery storage project are provided in Mr. Hans Jacob's testimony.

Finally, between 2022 and 2027, DEF will add close to 400 MW of combined

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cycle capacity that results from projects focusing on increasing the fuel efficiency of the combined cycle generating units. These projects are discussed in greater detail in Mr. Reginald Anderson's testimony.

In DEF's most recent approved rate settlement (FPSC Docket No. 20210016-EI), DEF anticipated the retirement of the two remaining coal units at Crystal River (Crystal River units 4 and 5) in 2034. Solar PV, complemented by a mix of combustion turbines and batteries for capacity, will be the cost-effective generation to replace most of that energy in the 2034 timeframe. DEF's plan to construct 450 MW of solar PV generation in 2025, and 300 MW in each year from 2026 through 2027, with additional annual amounts from 2028 through 2034, provides a path to meeting this goal through a measured and paced approach to bringing the solar onto the system which recognizes the challenges of building and interconnecting solar projects, helps maintain reliability as solar penetration increases, and considers the impact on customer rates. DEF also continues to consider cost effective market supply-side resource alternatives to enhance DEF's resource plan.

III. PROPOSED SOLAR INSTALLATIONS

Q. Please describe the Company's existing solar generating facilities.

A. DEF currently owns and operates a fleet of 23 PV solar generating facilities ranging in size from 0.25 MW to 74.9 MW. Most of these are state of the art single axis tracking facilities. Collectively, these units have a nameplate capacity of 1,186 MW and generated over 2.1 million MWh of electricity in 2023, more than 5% of DEF's total energy for load.

Q. Please explain DEF's proposed solar project build in the years 2025 through 2027.

A. DEF proposes a total of 14 solar projects to be installed and come into service during the period of 2025-2027, five of which are part of the proposed expansion of the existing CEC program. Each project is expected to have a nameplate output of 74.9 MW for a total nameplate output of 1,048.6 MW. When DEF completes these proposed solar installations, nearly 15% of DEF's generation will come from solar energy, which will be enough to power over 500,000 residential customers with clean, cost-effective energy. Specific details regarding the development and siting of these units can be found in the testimony of Ms. Vanessa Goff.

Q. Will these units contribute to firm reliable power?

A. Yes, although not at the full nameplate value. DEF recognizes that as solar penetration increases, including both DEF and customer-owned PV, the total dependable solar resource capability is influencing or shifting DEF's reserve planning focus later in the evening, beyond the on-peak period. DEF is accounting for this planning shift by deriving reduced summer capacity values of planned PV installations starting in 2025. The units to be installed in this period are projected to contribute 25% of their nameplate value during the net-peak hour (i.e., the hour of the summer in which the maximum amount of fuel fired generation is required). Collectively, these units will contribute approximately 262 MW of firm summer capacity to DEF's peak summer resources. This contribution will offset DEF's need to build or acquire other resources in the future.

Q. Is the primary value of these solar resources their contribution to firm capacity?

A. The solar resources contribute value in several ways. The contribution to firm capacity contributes value in that it reduces the need for other resources in the future. Solar energy is also an important low-cost resource that serves to offset the use of fuel fired resources, providing significant fuel cost reductions. This also serves as a physical hedge against future variability in the price of fuel, especially natural gas. Finally, a new value stream comes in the form of tax credits associated with the 2022 Inflation Reduction Act. These tax credits create a savings for each megawatt hour of solar energy produced which serves to reduce costs to customers and are discussed further in the testimony of Mr. John Panizza. While DEF is not currently ascribing additional value to these facilities for future GHG emissions regulations (e.g., a carbon price), the clean generation from these units and the resulting reduction in emissions from fossil fired generation also insulates DEF customers from the impact of potential future GHG regulation.

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Q. Will the proposed solar units reduce fossil fuel consumption?

A. Yes. DEF calculates that with our current fuel mix, each 74.9 MW solar facility displaces approximately 1.2 billion cubic feet of natural gas, 8,500 tons of coal and 7,500 barrels of fuel oil per year. Once all 14 of the proposed solar projects are in service, they will displace approximately 17 billion cubic feet of natural gas, 120 thousand tons of coal, and 100,000 barrels of oil per year compared with equivalent generation from our fossil fuel fleet.

Q. How does this translate into savings for the customer?

A. At 2023 market prices, each 74.9 MW solar unit reduced the DEF fuel expenditure by over $5 million. Relatively speaking, 2023 was a low fuel cost year. Fuel prices in 2022 were roughly double what they were in 2023; therefore, in addition to direct near-term savings, the solar units provide a natural hedge against future volatility in the price of fuel. Further, generation from the solar facilities will generate tax credits for DEF, the value of which will flow back to customers in the form of rate reductions. For each solar facility, these are expected to be approximately $4.8 million per year for the first 10 years of operation.

Q. Can all this be translated into an approximate rate impact?

A. Yes. Taking into account what DEF pays to own, maintain, and operate the facilities offset by the savings in fuel and tax credits, each solar facility adds a little less than 6 cents to a 1,000 kwh monthly bill during its initial years of operation. Due to

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depreciation and expected fuel price inflation, this amount is expected to decrease over time becoming a monthly benefit to customers in the sixth or seventh year of operation, out of a 30-year projected life, for each unit. If fuel prices increase more rapidly than overall inflation, this benefit will occur sooner. For instance, in 2022, when fuel prices were unusually high, the operating solar projects provided a net cost savings to customers.

Q. Why is 1048.6 MW nameplate capacity the right amount of solar to add to DEF's generating resource portfolio over the 2025 to 2027 timeframe?

A. As discussed previously, DEF's model has identified a larger amount of new solar generation, more than 5,000 MW, which is selected through 2034 to provide for load growth and to offset the generation from the retiring Crystal River units. DEF selected the 1048.6 MW of solar for construction in the 2025-2027 timeframe based on several factors, including site availability, opportunity for transmission interconnection, equipment availability, DEF's ability to integrate the solar into the system, and expected impact on customer bills.

Q. What will these proposed solar projects cost?

A. The projected project costs used in the cost effectiveness evaluation are detailed in MFR B-13. The development of the costs is described in more detail in Ms. Goff's testimony.

Q. How did DEF evaluate the cost effectiveness of the solar projects?

A. DEF calculated the cost effectiveness in the same manner that it performs cost effectiveness evaluations of numerous projects including the development of the Ten-Year Site Plan and the 2020 CEC filing and every Solar Base Rate Adjustment ("SoBRA") filing it has made pursuant to its 2017 Revised and Restated Stipulation and Settlement Agreement ("2017 Settlement"). DEF calculates the total system cost projected over the life of the solar projects for a scenario with the solar projects and compares it to the total system cost calculated for a scenario without the solar projects. Lower total system costs for the scenario with the solar projects represents savings to DEF's customers. As with our Ten-Year Site Plan, this analysis is performed using EnCompass Expansion Planning and Production Cost modeling tools to evaluate the production cost results. Project-specific capital costs come from the Renewables Development Team and revenue requirements are then developed. Finally, project-specific solar performance projections are developed using the PVSyst model and provided to the production cost model. These data become inputs to derive the system costs for the two cases developed with and without the solar projects in service.

The results of these differential cumulative present value of revenue requirement ("CPVRR") analyses, the difference between with and without the solar projects, are shown in Exhibit BMBH-3.

Q. Please describe the major assumptions used in developing the CPVRR analyses.

A. Two major assumptions used in developing the CPVRR analyses are the forecast of DEF system energy and demand ("Load Forecast") and the forecast of future prices for natural gas, coal, and oil ("Fuel Forecast"):

- Load Forecast – The analysis uses the load forecast presented as the base case load forecast in the DEF 2023 Ten-Year Site Plan ("TYSP") and filed with the commission April 1, 2023, which was developed in the fall of 2022. The process of developing the load forecast is explained in detail in Section VIII of this testimony.
- Fuel Price Forecast – This analysis uses the published fuel price forecast also utilized in DEF's 2023 TYSP.

Q. Are the proposed solar resources cost effective?

A. Yes. DEF analyzed the total system cost of the DEF system with and without the 14 solar projects which DEF proposes to build during the period 2025- 2027. The solar resources produce a savings of approximately $550 million compared to the alternate resource plan without these units. Details of DEF's analysis can be found in Exhibit BMHB-3.

IV. <u>CLEAN ENERGY CONNECTION ("CEC") PROGRAM EXPANSION</u>

Q. Please describe the CEC program.

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A. The CEC program is a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy centers. DEF introduced the CEC Program in 2021 and it was quickly subscribed to by many customers. The CEC program provides a path for customers who wish to have the environmental and sustainability benefits of participating in solar generation but cannot, or do not, wish to install it on their own premises to participate directly in DEF's solar generation expansion. As explained in Company witness Marcia Olivier's testimony, DEF is proposing to expand its existing CEC program.

Q. Why is DEF proposing to expand the CEC program?

A. DEF is proposing to expand the CEC program because of substantial additional demand from customers above the amount incorporated into the original CEC program starting in 2021.

Q. How many solar projects will be incorporated into the expanded CEC program?

A. Of the 14 proposed solar projects, DEF proposes to make five of those solar projects, totaling approximately 375 MW, available to subscribing customers under the expanded CEC program to support those customers' interests in meeting their environmental and sustainability goals.

Q. Was the cost effectiveness of the five CEC projects evaluated in the same

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manner as the 14 solar projects over all?

A. Yes. The evaluation of the subset of the five CEC projects was conducted by the same process using the same base assumptions as those used for the evaluation of the whole group of 14 proposed solar projects.

Q. Are the proposed solar projects designated for the CEC program cost effective?

A. Yes. As discussed previously in this testimony, DEF analyzed the total system cost of the DEF system with and without the 14 solar projects which DEF proposes to build during the period 2025- 2027. DEF also conducted an additional analysis of the subset of the five CEC projects alone. These projects were shown to be cost effective for DEF customers. The solar resources produce a savings of approximately $312 million compared to the alternate resource plan without these units. Details of DEF's analysis can be found in Exhibit BMHB-4.

V. COMBINED CYCLE EFFICIENCY IMPROVEMENT PROJECTS

Q. Does DEF plan to implement efficiency improvement projects at its existing natural gas fired combined cycle units?

A. Yes. DEF has begun work on projects at each of the combined cycle sites. Specific details on the projects can be found in the testimony of Mr. Reginald Anderson. Increasing the efficiency of these crucial baseload generating units will allow DEF to reduce the fleet-wide fuel consumption in both natural gas and coal. The projects

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are planned to come into service over a multi-year period beginning with the Osprey Energy Center, where the improvements were implemented in 2023, and extending through 2027 in coordination with scheduled major outages at the rest of the units.

Q. Will these projects increase the capacity of the combined cycle units?

A. Yes. Collectively, the projects at seven existing combined cycle units will raise the capacity of the combined cycle fleet by almost 400 MW. This increase in capacity will offset the need to construct future generation. In addition, because the capacity is being added at operationally flexible baseload units, this will enable additional future solar development as it will provide energy in periods of low solar generation and will add load following capacity to match intermittent solar generation.

Q. Was the cost effectiveness analysis of these projects done in a similar manner to the process previously described above for the solar analysis?

A. Yes. As described above, the analysis was conducted by creating two cases for evaluation, one with the upgrade projects and one without.

Q. Will these projects produce savings for customers?

A. Yes. These projects are expected to produce almost $400 million in savings to customers primarily through fuel savings. Because fuel costs are trued up annually, these savings will be passed to customers in the short term. These savings do not include any potential benefit due to future carbon regulation, which would further increase the value of these projects. Details of DEF's cost effectiveness evaluation for these projects are shown in Exhibit BMHB-5.

VI. BATTERY ENERGY STORAGE

Q. Please provide an overview of DEF's current battery energy storage portfolio.

A. All of the energy storage systems from DEF's 50 MW battery storage pilot program (Battery Storage Pilot) were placed in-service by late 2023. These projects may serve a variety of purposes including, but not limited to substation upgrade deferral, distribution line reconducting deferral, power reliability improvement, frequency regulation, Volt/VAR support, backup power, energy capture, and peak load shaving. Going forward, DEF is gathering data on the performance of these units and will use the data gathered from the operation of these Pilot Program sites to evaluate the opportunities and uses of future DEF battery development. The increase of solar energy generation on the system provides a unique opportunity for energy storage assets to assist in integration of these intermittent resources and shift energy from lower system value periods to times with higher system value.

Q. Is DEF proposing to add additional Battery Energy Storage projects in the 2025-2027 period?

A. Yes. DEF is proposing to build and commission a 100 MW / 200 MWH battery energy storage system with an in-service date in 2027. The project will utilize lithium-ion energy storage and be located to maximize the Standalone Storage

Investment Tax Credit ("ITC") passed into law as a part of the Inflation Reduction Act of 2022. The increase of solar energy generation on the system provides a unique opportunity for energy storage assets to assist in integration of these intermittent resources and shift energy from lower system value periods to times with higher system value. Further details about this battery energy storage project are included in witness Hans Jacob's testimony.

Q. Is the proposed Battery Storage project cost effective?

A. Valuation of battery cost effectiveness is still evolving. DEF performed a cost effectiveness analysis of the battery project using the EnCompass tool, which is the standard tool used in the evaluation of DEF generating assets. The results of this analysis are shown in Exhibit BMHB-6. The results of this analysis showed a range of results from a lifetime cost of $3.2 million (over the 15-year life of the battery) to a lifetime savings of $5.7 million. DEF believes that both of these values understate the actual value of the battery because these values are based solely on the ability of the battery to store energy in low-cost hours and discharge it in higher cost hours (energy arbitrage). While this provides a significant value, essentially equal to the installation and operating cost of the battery, it does not capture other values streams such as the battery's use in sub-hourly periods to offset rapid changes in solar output or shortcomings in system ramp capability that might otherwise lead to additional peaker starts. Similarly, the battery may be used to prevent solar curtailment which will allow the increased generation of production tax credits in some hours, another system condition that is not well represented in the modeling. Avoiding or reducing solar curtailment in approximately 30 hours per year over the life of the battery would offset the estimated $3 million shortfall in the battery value in the worst projected case.

The range of values shown in Exhibit BMHB-6 demonstrates another area of uncertainty as it is tied to differing assumptions regarding treatment of the Investment Tax Credit allowed under the 2022 Inflation Reduction Act. The precise conditions for monetization of the tax credits in 2027 are not known and will depend on Duke Energy's tax position as well as on the market for tax credits if Duke Energy cannot fully utilize them. In these projections, DEF shows a range from $5.7 million (Duke fully utilizes the credit) to $-3.2 million (the credits are sold at a 10% discount) and assumes that Duke chooses to normalize the resulting tax benefit over the project life.

Taken in aggregate, this project is expected to provide value to DEF customers through energy arbitrage, system balancing and solar smoothing, peaker start reduction, and capture of otherwise curtailed solar generation. The values in Exhibit BMHB-6 show that the project essentially breaks even when counting only the energy arbitrage value.

VII. IMPACT ON COST ALLOCATION

Q. Do these changes to the generating portfolio influence the way that DEF values

its new generating units?

A. Yes. As can be seen in the Exhibits BMHB-3 and BMHB-5, showing the cost effectiveness of the proposed solar projects and the combined cycle efficiency improvement projects, these projects derive a large portion of their value from fuel savings and low-cost energy generation. In the example of the combined cycle efficiency projects, DEF found that while the projects add capacity, which has a real value, the primary driver for pursuing these projects is the fuel savings opportunity, which will have immediate benefit to customers. DEF expects the focus on energy efficiency and cost as a complement to traditional capacity and reliability interests to increase in future years in projects that may be proposed beyond the period covered by this proceeding.

Q. Does this shift have implications for cost allocation?

A. This topic is discussed in greater detail in the testimony of Ms. Marcia Olivier, but from a resource planning standpoint, there is greater emphasis on units that are designed around the need to control fuel costs. Over the last two decades, DEF has invested in the construction of combined cycle units, which over the long term have created savings for customers, but which are subject to greater short term fuel cost variability. In this way, they emphasize the importance of energy as a component of the overall customer cost. Looking forward, the industry expects a greater emphasis on energy adequacy as more intermittent resources become part of the generating portfolio. These factors support a shift in the cost allocation so that the customer's energy use is a more significant factor in contribution to cost of service.

VIII. LOAD FORECASTING

Q. What is the purpose of a load forecast?

A. The load forecast is used in both the Company's planning and budget processes. The load forecast enables the Company to estimate the likely number of customers it will serve in the future, the amount of electric energy it will sell to those customers, the peak demand for power, and the time at which the customer demand will be greatest. DEF must estimate or project how much energy its customers (old and new) will consume in the future and when that consumption is likely to take place to serve customers in a cost-effective and reliable manner.

Q. When did the Company perform its load forecast?

A. The Company prepared the load forecast upon which this base rate filing is based in late February and early March 2023 (the "Spring 2023 Load Forecast"). The Spring 2023 Load Forecast accounts for the impact of then current economic conditions on the Company's anticipated future customer, energy, and peak demand by including the most recent economic and demographic inputs available. The Spring 2023 Load Forecast was used to develop the revenue forecast and resulting 2025, 2026, and 2027 Company budgets. It serves as the basis for the development of the Company's MFRs. The Company's Spring 2023 Load Forecast (customers, energy sales, and demand) for 2024 and the test years (2025-2027) is reflected in Exhibit BMHB-2.

IX. FORECAST METHODOLOGY

Q. Please provide us with an overview of the forecasting methodology used to develop the load forecast.

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

Q. Please explain how DEF develops the Energy and Customer Forecast.

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

Q. What process does DEF use to forecast the residential sector?

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

Q. What process does DEF use to forecast the commercial sector?

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

- Heating
- Cooling
- Ventilation
- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting

C4-738

- Office Equipment (PCs)
- Miscellaneous

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

Q. What process does DEF use to forecast the industrial sector?

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

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

The projection of industrial accounts is expected to continue declining with manufacturing employment as a primary driver.

Q. What process does DEF use to forecast the street lighting sector?

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

C4-740

Q. What process does DEF use to forecast the Public Authorities sector?

A. Energy sales to public authorities ("SPA"), comprised of federal, state, and local government operated services, are projected to decline within the DEF's service area. This is a result of lower projected customer growth/customers moving to the Street Lighting class. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e., public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided along with state government GDP. These variables, along with cooling degree-days and the sales month billing days, explains most of the variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use throughout the year. The SPA customer forecast is projected linearly as a function of a time trend.

Q. What process does DEF use to forecast the sales for resale sector?

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

C4-741

The municipal sales for resale or wholesale class includes a number of customers, divergent not only in scope of service (i.e., full, or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. In each case, these customers contract with DEF for a specific level and type of stratified capacity (MW) needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using information provided by the purchaser who better understands their needs. Electric energy growth and competitive market prices will dictate the amount of wholesale demand and energy throughout the forecast horizon. In the period 2025 - 2027 Seminole Electric Cooperative is the only wholesale, or sales for resale, customer of DEF in the current forecast.

Q. Please explain how DEF develops the Peak Forecast.

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

C4-742

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

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

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

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

Q. What major assumptions are used throughout DEF forecasts as a part of this methodology?

A. A number of key assumptions have generally been used in DEF forecasts for several years. These key assumptions for the current load forecast are as follows:

1. Weather conditions for energy sales are based on a 30-year average of conditions at specific weather stations in Florida.

2. The customer forecast relies on Moody's population estimates for the 29 counties served by the utility, along with economic projections from Moody's Analytics and Energy Information Administration ("EIA") surveys.

3. The phosphate mining industry heavily influences industrial sales within the service area, with global factors such as foreign competition, agricultural industry conditions, exchange rates, international trade pacts, and environmental regulations affecting energy consumption.

4. The utility has contractual obligations with wholesale customers, and the forecast considers these agreements and the potential for customers to self-generate.

5. Assumption of successful renewal of all future franchise agreements.

C4-745

6. The forecast incorporates demand and energy reductions as per Florida Public Service Commission ("FPSC") approved Demand-Side Management ("DSM") goals.

7. Impacts from Plug-in Hybrid Electric Vehicles ("PHEV") and customer-owned renewable generation (primarily solar PV installations) are considered for both energy and peak demand.

8. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are included.

9. Economic assumptions are based on the most recent semiannual economic outlook report from Moody's Analytics.

These assumptions are made with the expectation that the regulatory environment and the utility's obligation to serve retail customers will remain consistent throughout the forecast horizon. For wholesale customers, the forecast only includes generation resources if there is a long-term contract in place.

Q. Please describe the economic assumptions used in the Spring 2023 Load Forecast.

A. The economic outlook for this forecast was developed in the winter of 2022-2023. In January 2023, the U.S. economy faced a challenging economic landscape characterized by aggressive tightening of monetary policy by the Federal Reserve. The central bank, underlining a hawkish stance, signaled further rate increases into 2023 and 2024, with plans to shrink its balance sheet through quantitative tightening. The funds rate target was projected to reach 4.5% to 4.75%, well above the estimated long-run equilibrium of 2%. This monetary policy approach was driven by concerns about persistently high inflation resulting from pandemic-related disruptions to global supply chains, labor markets, and geopolitical events such as Russia's invasion of Ukraine. Taking resilient job growth and low unemployment into account, the Federal Reserve aimed to address inflationary pressures. Ten-year Treasury yields reflected these actions, reaching close to 4% at the time of Moody's January 2023 outlook. Simultaneously, fiscal policy shifted from expansionary measures during the pandemic to a more restrictive approach. The recently passed Inflation Reduction Act aimed to raise substantial funds over the next decade through increased taxes and reduced spending. This legislation targeted climate change, healthcare costs, and future budget deficits. While previous fiscal support during the pandemic totaled over $5 trillion, the focus shifted to deficit reduction, with the federal government expecting a narrower deficit of $850 billion in fiscal 2023. The U.S. dollar, buoyed by the Federal Reserve's tight monetary policy and global uncertainties, remained strong, with expectations of its resilience even as threats such as the pandemic and geopolitical tensions receded. At the state level, Florida's economy outpaced the nation's but faced challenges from higher prices and rising interest rates, impacting job creation, income gains, and the housing market. Additionally, the vital tourism industry in Florida felt the effects of a weakened U.S. economy.

It is with this background that the DEF Customer, Energy and Peak Demand forecast was developed and the environment in which the Moody's Analytics January 2023 U.S. forecast and Florida forecast was applied.

Major assumptions were as follows:

- Preparation for the European Union sanctions, weakening global economies, demand destruction from high oil prices had all pushed oil prices below expectations. Moody's expected lower Russian exports, the end of Strategic Petroleum Reserve releases, and the reopening of the Chinese economy to lift oil prices, but not as high as previously thought. However, lower forecast prices in 2023 implied a projection of less drilling and higher prices in 2024.
- In January 2023, the economy was considered to be at a full employment level. A full-employment economy is one with an unemployment rate around 3.5%, a 62.5% labor force participation rate, and a prime-age employment-to-population ratio a little north of 80%.
- The Fed raised the fed funds rate 50 basis points in December 2022, and the forecast was for two additional increases of 25 basis points in early 2023. The Fed forecast to pause, despite hawkish rhetoric from Chairman Jerome

Powell, but cuts were not expected to begin until 2024. The assumption was that the reduction in the Fed's balance sheet would remain on autopilot.

- The 10-year U.S. Treasury yield was expected to steadily increase until late Fall 2023.
- With all these factors, the forecast called for a decrease in Real GDP's year over year growth rate from 3.99% in 2022 to 1.33% in 2023. The growth rate would then gradually increase to 2.74% by 2027, still falling short of 2022s level of growth.
- A decrease in total employment's year over year growth rate from 5.29% in 2022 to 2.23% was also forecast for 2023. The growth rate would remain relatively flat at 0.88% by 2027, signifying a stagnating labor market during the forecast period.

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

Q. Is the forecasting methodology used to develop the load forecast consistent with DEF's load forecasting policy and practice?

A. Yes, it is. DEF followed its standard forecasting methodology in developing its load forecast. This forecasting methodology has been used for years at DEF to forecast load with substantially accurate past results when actual load is compared to prior forecasts, excluding anomalous, unpredictable events such as the post-9/11, global financial crises, and the COVID-19 pandemic. DEF's load forecasting methodology is also consistent with generally accepted, utility industry standard methodologies for load forecasts. As a result, DEF is confident that its load forecast was a reasonably accurate projection of future load in 2025, 2026, and 2027 based on the information available in early 2023.

X. <u>LOAD FORECAST SUMMARY</u>

Q. What conclusions can be drawn from DEF's load forecast?

A. The total number of retail customers continues to grow during the forecast period, with the rate of change being effectively unchanged. The historical 10-year compound annual growth rate ("CAGR") from 2014-2023 was 1.65% vs 1.68% projected from 2024-2027. At the same time, total retail sales over the period from 2024-2027 are expected to grow at a lower rate than the previous 10-year period. The historical 10-year CAGR for total retail sales from 2014-2023 was 1.03% vs only 0.15% projected for 2024-2027. The lower growth rate during this period is

C4-750

attributed to a decrease in residential sales. The historical 10-year CAGR for residential sales from 2014-2023 was 1.5% vs –0.2% projected. While customer growth is projected to continue the growth trend of the previous 10 years, there are several drivers causing a decrease in residential sales in the forecast period. Total employment is an economic driver for residential sales. At the time of the forecast, total employment was expected to remain flat from 2023-2024 and grow at a lower rate from 2025-2027. Furthermore, energy efficiency programs and solar adoption continue to grow causing residential sales to decrease. Flat employment, increasing energy efficiency, and increasing rooftop solar adoption all contribute to the negative residential sales growth rate from 2024-2027.

General Service sales are expected to remain consistent with the previous 10 years. The historical 10-year CAGR for General Service Sales was 0.5% and a 0.5% growth rate was projected. General Service customer growth also remained strong with a historical CAGR from 2014-2023 of 1.2% and 1.3% projected. Electric vehicle adoption is expected to contribute to increased sales. Energy efficiency and rooftop solar adoption for this class are much lower than the residential class and therefore are not causing the same negative impact to sales.

Industrial sales are expected to increase over the forecast period. The historical 10-year CAGR for Industrial Sales was 0.4% vs 0.8% projected. This is primarily due to the projected expansion of one large customer.

C4-751

Overall, residential sales experience a slight decrease due to flat employment, and growing energy efficiency and rooftop solar adoption while General Service and Industrial sales outpace the growth of the previous 10 years. As residential sales are the largest component of DEF sales, the overall impact projected for the 2025-2027 period is one of lower growth than over the previous period.

XI. <u>LEVY COUNTY LAND</u>

Q. Has the Company included Levy County Land in rate base in this case?

A. Yes. Approximately $94 million for Levy County land is included in rate base in this case as Plant Held for Future Use.

Q. Is it probable that the Company will use the Levy County Land for future generation or transmission projects?

A. Yes. It is probable that the land in Levy County will be used for a regulated project in the future. DEF recognizes that this property has multiple potential uses. The DEF property has access to a water source but is not at risk for storm surge, and it provides access to connect to DEF's power grid, which makes it an attractive site for future conventional generation. DEF also anticipates that scheduled upgrades to the transmission system will increase transmission access in this area in the 2025-2030 timeframe. Because of the large area of this property, and the above features, DEF envisions that this property could have multiple potential uses. Given the above, this site may be utilized for new generation needed in response to the retirement of the coal units at Crystal River North in 2034. Beyond that period, in the 2038-2048 timeframe, this will be an attractive site for addition of a new Zero-Emitting Load Following Resource. DEF is exploring different technologies including the potential development of next generation nuclear (Small Modular Reactor) technology. The site remains especially valuable given its access to water, transportation, and transmission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C4-753

(Whereupon, prefiled direct testimony of Rebekah E. Buck was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC

Docket No. 20240025-EI
Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

REBEKAH E. BUCK

On Behalf of Duke Energy Florida, LLC

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Rebekah E. Buck, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Director of Allocations and Reporting. DEBS provides various administrative and other services to Duke Energy Florida, LLC ("DEF" or "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. Please briefly describe your education and professional experience.

A I graduated with a Bachelor of Arts Degree in Communication Studies from the University of North Carolina at Chapel Hill and have a Master's Degree in Accounting from the University of North Carolina at Charlotte. I am a Certified Public Accountant in North Carolina. I joined Duke Energy in 2010 in the Corporate Controller's Department as a Finance Associate, supporting the Commercial Power business. In 2012, I supported the Duke Energy Generation Services, progressing from an Accounting Analyst to a Lead Accounting Analyst. In 2018, I moved to a Lead Wholesale Renewables Analyst position on the Distributed Energy Technology team where I provided financial modeling support for various regulated renewables projects across the Duke Energy utilities. In 2019, I returned to the Corporate Controller's Department and Commercial Renewables Accounting team as an Accounting Manager. In 2021, I was promoted to Manager

Accounting II and offered the opportunity to head up the Account Reconciliation Center of Excellence ("ARCOE") for Duke Energy. The ARCOE was created to implement standardization and efficiencies across the mass inventory of account reconciliations performed at the Company. In July of 2023 I was promoted to my current role, Director of Allocations and Reporting.

Q. Please briefly describe your duties as Director of Allocations and Reporting.

A. I am responsible for various accounting activities, including the cost allocation processes for service company costs utilized for Duke Energy and its affiliates, including allocations to DEF.

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

A. My testimony in this proceeding addresses the various cost assignment processes utilized by DEF and its affiliates, including its service company, DEBS, which in the ordinary course of business provide services to each other. I will also provide an overview of the other cost allocation methodologies utilized by DEF including cost pools, loading rates, and indirect overhead allocations. I discuss the primary service agreements used by DEF to enable the sharing of expertise and personnel between and among the Duke Energy family of companies and to assign costs for such services that result in economies of scale and services that benefit DEF customers. These service agreements include the following: (1) the Service Company Utility Service Agreement (also referred to herein, as the "DEBS Service Agreement"); (2) the Operating Companies Service Agreement; (3) Operating Company/Nonutility Companies Service Agreement; and (4) the Intercompany Asset

Transfer Agreement. In my testimony, I briefly describe the history of these agreements. I also describe the processes used to assign costs to the various parties under those agreements as well as the nature and types of cost assignment that DEF experiences as an electric utility and wholly-owned subsidiary of Duke Energy. These processes ensure that affiliate originating costs are appropriately included on DEF's books and records, and the forecasts of these costs are consistent with appropriate allocations of cost responsibility and avoid cross-subsidization. I sponsor certain information that I supplied to DEF witness Michael O'Hara for his use in developing the forecasted financial data, which includes any cost reductions in overhead costs and assumptions on process improvements reflected in the Administrative & General costs.

Q. Do you sponsor any exhibits or minimum filing requirements?

A. Yes. I sponsor and have included the following exhibits:

Exhibit REB-1- Service Company Utility Company Service Agreement;

Exhibit REB-2 - Operating Companies Service Agreement;

Exhibit REB-3 - Operating Company/Nonutility Companies Service Agreement;

Exhibit REB-4 - Intercompany Asset Transfer Agreement; and

Exhibit REB-5 - 2023 Service Company Cost Allocation Rate Schedule.

I sponsor or co-sponsor the following minimum filing requirements (MFRs):

C-6	Budgeted Versus Actual Operating Income And Expenses
C-8	Detail Of Changes In Expenses
C-9	Five Year Analysis - Change In Cost
C-12	Administrative Expenses

C-13	Miscellaneous General Expenses
C-14	Advertising Expenses
C-15	Industry Association Dues
C-16	Outside Professional Services
C-30	Transactions With Affiliated Companies
C-31	Affiliated Company Relationships
C-32	Non-Utility Operations Utilizing Utility Assets
C-33	Performance Indices
C-35	Payroll & Fringe Benefit Increases Compared To CPI
C-36	Non-Fuel Operation And Maintenance Expense Compared To CPI
C-37	O&M Benchmark Comparison By Function
C-41	O&M Benchmark Comparison By Function
F-3	Business Contracts With Officers Or Directors

These exhibits are true and accurate.

II. THE SERVICE AGREEMENTS

Q. Do all charges for DEF originate on DEF's books?

A. No. Charges can originate either on DEF's books for its own operations or can originate from its parent company and/or other affiliated companies pursuant to several affiliate service agreements. These services enable DEF to provide safe and reliable utility service to its Florida customers at a reasonable price.

Q. What is meant by the term "cost assignment"?

A. "Cost assignment" refers to the process of assigning the costs incurred in providing a product or service to the company or companies receiving such product or service. In DEF's case, cost assignment entails ensuring that DEF bears the costs incurred on DEF's behalf by affiliate companies, such as DEBS, and ensuring that costs incurred by DEF on behalf of affiliate companies are borne by the affiliate companies.

Q. Please describe DEBS.

A. DEBS is a Federal Energy Regulatory Commission ("FERC") authorized service company that provides various administrative and other services to DEF and other affiliated companies of Duke Energy. DEBS provides a variety of administrative, management, and support services (sometimes referred to as "functions"), such as accounting and human resources, to the Duke Energy family of companies pursuant to the agreements discussed below.

Q. Please briefly describe the various service agreements that enable DEF to provide safe, reliable, and reasonable service to its Florida customers.

A. DEF has several service agreements in place that allow the Company to provide services to, or receive services from, the Duke Energy family of companies that are incidental or necessary to the provision of utility service. These agreements provide for the standard procedures and defined accounting processes for cost assignment that allow these services to occur on an equitably priced basis among all parties.

I have attached the four major service agreements to my testimony, all of which were effective when the Company commenced these proceedings.

Exhibit REB-1 is the Service Company Utility Service Agreement that governs the provision of various services and the associated cost allocations to DEF for the services DEBS provides.

Exhibit REB-2 is the Operating Companies Service Agreement that governs services performed between or among Duke Energy's regulated utility operating companies and the cost allocations or assignments for providing and receiving those services.

Exhibit REB-3 is the Operating Company/Nonutility Companies Service Agreement, which governs the services performed and cost allocations between DEF and its non-utility affiliates.

Exhibit REB-4 is the Intercompany Asset Transfer Agreement that allows for the transfer of assets by and between DEF and its regulated utility affiliates.

Finally, Exhibit REB-5 is the Service Company Cost Allocation Rate Schedule that outlines the allocation percentages, which reflect the current underlying foundation of the ratios used to allocate costs for the services DEBS provides.

Q. Has DEF historically relied upon service agreements to serve its Florida customers?

A. Yes. These service agreements allow DEF, and in turn, its customers, to have access to equipment and personnel that are common to utility operations and share in those costs between multiple businesses as opposed to maintaining separate pools of personnel. The use of service agreements has helped DEF, and its regulated utility affiliates, manage staffing levels and costs through the sharing of common business functions and have ready access to experienced and expertly trained personnel to manage its business and various utility functions. Absent the ability to share these resources, DEF would have to maintain its own independent organizations and systems, as well as cost responsibility, for various operations including, but not limited to, engineering, construction, operations and maintenance, installation services, equipment testing, generation technical support, environmental health and safety, procurement services, accounting, human resources, legal, and other necessary business functions.

Q. How has DEF benefited from this arrangement?

A. The Company has benefited from the economies of scale that occur from being part of a larger corporate family that are not present as a standalone entity. By sharing resources and personnel, DEF is able to provide service to its customers without having to invest in its own full-time corporate personnel and resources that are otherwise able to be shared among a family of companies.

In other words, DEF has been able to share in common business functions rather than maintain its own dedicated and thus duplicative functions. Through the service agreements, DEF has also taken advantage of the expertise, resources, and key personnel employed by its sister utilities, allowing the Company to utilize the economies of scale and best practices that exist with an organization the size of Duke Energy.

Q. Have there been any changes to these agreements since the time of the Company's last base rate case in 2021?

A. No, there have not been any significant changes since the 2021 Settlement Agreement.

A. <u>Service Company Utility Service Agreement</u>

Q. Please briefly describe the Service Company Utility Service Agreement.

A. This agreement permits DEBS to provide services that are corporate or general utility in nature and are used by various business units, including DEF. A copy of this agreement is included as Exhibit REB-1. In general, the services provided by DEBs include, but are not limited to:

- Information Systems, Meters, and Transportation;
- Power Planning and System Maintenance;
- Marketing and Customer Relations;
- Transmission and Distribution Engineering and Construction;
- Power Engineering and Construction;
- Human Resources;
- Supply Chain;
- Facilities;
- Accounting;
- Operations;
- Public Affairs;
- Legal;
- Rates;
- Finance;
- Rights of Way;
- Internal Auditing;
- Environmental, Health, and Safety;
- Fuels;
- Investor Relations;
- Planning; and
- Executive.

By the terms of the Service Company Utility Service Agreement, compensation for any service rendered by DEBS to its utility affiliates is the fully embedded cost thereof (*i.e.*, the sum of: (i) direct costs; (ii) indirect costs; and (iii) cost of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. The affiliate companies receiving services from DEBS are referred to as "client companies." Each client company is required to reasonably cooperate with each respective service provider to record billings and payments in their common accounting systems.

B. <u>Operating Companies Service Agreement</u>

Q. Please briefly describe the Operating Companies Service Agreement and its history.

A. Like the Service Company Utility Service Agreement, the Operating Companies Service Agreement has been in place in some form for decades. Under this agreement, DEF and its utility affiliates, Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Duke Energy Indiana, Inc.; Duke Energy Ohio, Inc.; Duke Energy Kentucky, Inc.; and Piedmont Natural Gas Company, Inc., are permitted to provide and receive services to and from each other in the normal course of conducting business at the providing company's fully embedded cost. A copy of this agreement is included as Exhibit REB-2.

The services that may be provided between affiliate operating companies may include, but are not limited to the following:

- Engineering and Construction;
- Generation Technical Support;
- Operations and Maintenance;
- Environmental, Health, and Safety;
- Installation Services;
- Customer Operations;
- Equipment Testing; and
- Procurement Services.

By the terms of the Operating Companies Service Agreement, compensation for any service rendered between utility affiliates is the fully embedded cost thereof (*i.e.*, the sum of: (i) direct costs; (ii) indirect costs; and (iii) cost of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. Each client company is required to reasonably cooperate with each respective service provider to record billings and payments in their common accounting systems.

C. Operating Company/Nonutility Service Agreement

Q. Please describe the Operating Company/Nonutility Service Agreement.

A. DEF is a party to the Operating Company/Nonutility Service Agreement, pursuant to which DEF and certain of its non-utility affiliates are authorized to provide certain services to one another. These services are priced using asymmetric pricing, at an amount consistent with the following requirements:

(a) In circumstances where DEF is the provider, non-utility affiliates shall pay the higher of the fully embedded cost thereof and the comparable market price (if any); and

(b) In circumstances where a non-utility affiliate is the provider, DEF shall pay the lower of the fully embedded cost and the comparable market price (if any).

A copy of this agreement is included in Exhibit REB-3. The permitted services provided by DEF to certain of its non-utility affiliates may include, but are not limited to the following:

- Engineering and Construction;
- Operations and Maintenance;
- Installation Services;
- Equipment Testing;
- Generation Technical Support;
- Environmental, Health, and Safety; and
- Procurement Services.

The types of services that may be provided by certain non-utility affiliates to DEF, include, but are not limited to, the following:

- Information Technology Services;
- Monitoring;
- Surveying;

- Inspecting;
- Constructing;
- Locating and Marking of Overhead and Underground Utility Facilities;
- Meter Reading;
- Materials Management;
- Vegetation Management; and
- Marketing and Customer Relations.

By the terms of the Operating Company/Nonutility Agreement, requests for services are to be made in writing, in substantially the same form as set forth in "Exhibit A" of the Agreement. Compensation for any service rendered between DEF and its non-utility affiliates must follow the asymmetric pricing requirements listed above for all transactions between utilities and their non-utility affiliates. This asymmetric pricing requirement excludes services provided by service companies or services between and among regulated utility affiliates.

DEF provides non-tariffed goods or services to a party to this agreement at the greater of cost or market price but pays the lesser of cost or market price for any goods or services received under this agreement.

Q. Please explain how services between DEF and its affiliates that are not covered by the aforementioned service agreements are priced.

A. Non-covered services, as well as non-utility affiliates that are not a party to the cost-based Nonutility Service Agreement, must follow asymmetric pricing requirements for any transaction with DEF.

D. <u>The Intercompany Asset Transfer Agreement</u>

Q. Please explain and describe the Intercompany Asset Transfer Agreement.

A. DEF is a party to the Intercompany Asset Transfer Agreement. This agreement permits the transfer of assets, excluding commodities, between and among DEF and its regulated utility affiliates at the transferring company's fully allocated cost, subject to certain limitations. A copy of this agreement is included as Exhibit REB-4.

E. Conclusion

Q. In your opinion, do the various service agreements fairly and accurately allocate costs and revenues to DEF?

A. Yes, these agreements are designed to fairly allocate costs and revenues among the participants and in my opinion, they have done so.

III. COST ALLOCATIONS

A. Overview of Cost Allocations

Q. Please describe what is meant by the term "cost."

A. "Cost," as used in the Service Company Utility Service Agreement and Non-Utility Service Agreement, means fully embedded cost, which is the sum of: (1) direct costs; (2) indirect costs; and (3) cost of capital. Direct costs include labor, materials, and the expenses incurred specifically for a particular service and any associated loadings. Indirect costs include labor, materials, and other expenses, as well as any associated loadings, that cannot be directly identified with any particular service. Indirect costs include, but are not limited to, overhead costs, administrative support costs, and taxes. Cost of capital represents financing costs, including, but not limited to, interest on debt and a fair return on equity to shareholders based on the Florida Public Service Commission-approved cost of equity.

Q. Please describe the cost allocations that affect DEF and its affiliates.

A. In general, there are three primary categories of cost allocations that affect DEF and its affiliates: (1) cost allocations from DEBS; (2) cost allocations for goods and services provided between and among DEF and its sister regulated utilities; and (3) loadings for various costs pools that are applied to labor, materials, contracts, and vehicles depending on the type of cost.

DEF also provides various services and goods to and receives various services and goods from its regulated and nonregulated affiliates as set forth in the various service agreements I previously described. These goods and services are also described in my Exhibit REB-5, which is the Service Company Cost Allocation Rate Schedule.

Q. What are "loadings"?

A. "Loadings" represent costs that are incurred and aggregated in "cost pools," which are then subsequently "loaded" out (*i.e.,* allocated) to specific entities and projects by attaching an additional charge ("loading rate") to the associated direct cost. Duke Energy's loadings include fringe benefits (*e.g.*, medical, dental, pension, post-retirement); unproductive time (*e.g.*, vacation, holiday, sick time) for actuals only; stores, freight, and handling (*e.g.*, material management labor, freight); transportation (*e.g.*, vehicle leases, fuel, oil), and payroll taxes (*e.g.*, Federal Insurance Contributions Act ("FICA") taxes, and state and federal unemployment taxes). Loading rates are determined through annual studies of both actual and budgeted information and are calculated by dividing the anticipated component costs by anticipated labor cost, material issues, or vehicle utilization, as applicable.

Q. Are there other significant types of loadings that need to be addressed?

A. Yes. There is a DEBS Service Company Overhead Loader that is applied to all DEBS labor. There is a Utility-to-Utility Affiliate Loader, which is applied when employees of one utility charge to another utility or charge time to a non-regulated account. There are also functional indirect overheads, which spread common costs within a function (*e.g.* Distribution, Fossil) of DEF across a common allocator, typically department labor.

Q. What is the purpose of the DEBS Service Company Overhead Loader?

A. As part of a fully distributed cost, an overhead component is charged to affiliates as a percentage of DEBS labor costs, whether direct charged, distributed, or allocated. This overhead represents the cost of shared services provided by shared services employees. The rate is based on historical enterprise and governance costs in the following functions: Information Systems, Facilities, Transportation, Human Resources, Supply Chain, Accounting, Public Affairs, Legal, Finance, Internal Auditing, Environmental, Health and Safety, Investor Relations, Planning, and Executive. The purpose of this loader is to better align the cost of shared services provided by shared services employees, following their actual labor charged. The offset for the Overhead Loader in effect reduces the dollars being allocated through the normal service company allocations process. The Overhead Loader is calculated and updated annually as part of the budget.

Q. What is the purpose of the Utility-to-Utility Affiliate Loader?

A. The purpose of this loader is to assign fully burdened costs to utility labor. Charges are generated when a utility employee charges labor to a business unit outside their jurisdiction. For example, when a DEF employee charges outside of the DEF utility, not only is the labor and associated benefit load costs moved off of DEF's books, but a portion of costs for administrative and governance costs, training, facilities, and supervisory costs that are charged by or allocated to DEF are also removed from DEF's regulated books. The Utility-to-Utility loader is calculated annually and utilized for actuals during the calendar year.

Q. Please describe the functional indirect overheads process.

A. Overhead costs are accumulated for a function (*e.g.,* production, transmission, distribution) in a functional departmental pool. These costs could include dollars allocated or direct charged from DEBS as well as departmental management costs. These costs are then typically cleared as an overhead load on department labor following the same account charged by employees of the department. To the extent a department employee is working on a capital project, a portion of these costs are then capitalized.

B. Cost Allocations Under the Service Agreements

Q. Please describe how costs incurred by DEBS are accounted for under the service agreements.

A. DEBS maintains an accounting system in which all its costs are accumulated. These costs are charged to the appropriate client companies monthly, using one of the three approved methods of assignment.

Q. What are the approved methods of assignment?

A. The approved methods of assignment are: (1) directly assignable; (2) distributable; and (3) allocable.

Q. Please describe each method of assignment.

A. The directly assignable basis of cost assignment is utilized to directly charge costs for services specifically performed for a single client company. Costs are direct charged to the extent possible. The distributable cost assignment method is used to assign costs for services rendered specifically for two or more client companies. The distributable cost assignment method simply means that the cost is either directly charged or allocated to two or more, but not all, of the client companies. For example, costs incurred on behalf of DEF and Duke Energy Progress would be directly charged or allocated, as appropriate, and distributed across the two applicable entities in which these costs related. The allocable method of assignment is used to allocate costs for services of a general nature, which are applicable to all client companies or to a class or classes of client companies. The objectives of the cost distribution process are to:

- Meet regulatory requirements.
- Ensure that each affiliate shares in and is appropriately charged for the relevant shared services costs.
- Assist affiliates in understanding the cost drivers and basis for allocation of shared services costs that affect their operating results.
- Provide an accounting model whereby affiliates can see how much is allocated to them for each shared service.

Q. What types of expenditures are directly assigned from DEBS to DEF?

A. DEBS employees who work on a project specifically for DEF charge their labor and expenses directly to DEF. For example, the legal services function will charge DEF directly for work performed specifically for DEF. This is determined by the number of hours spent on jurisdictional activities.

Q. Please explain the allocable charges from DEBS to DEF.

A. Allocable charges to DEF are for a portion of expenditures originating on DEBS' books that are applicable to DEF and one or more other client companies, but which are not directly assignable to DEF. These charges are allocated to DEF based on allocation ratios set forth in Appendix A of the DEBS Service Agreement. For example, costs related to Investor Relations activities are applicable to all Duke Energy affiliates but cannot be directly charged to any one affiliate. Those costs are allocated to all affiliates using the allocation factor described for the Investor Relations Function in Appendix A of the DEBS Service Agreement.

Q. What are the allocation methods specified in Appendix A of the DEBS Service Agreement?

A. Twenty allocation ratios are specified in the Utility Service Agreement. These ratios are the:

(1) Sales Ratio;
(2) Electric Peak Load Ratio;
(3) Number of Customers Ratio;
(4) Number of Employees Ratio;
(5) Construction-Expenditures Ratio;

(6) Miles of Electric Distribution Lines Ratio;

(7) Circuit Miles of Electric Transmission Lines Ratio;

(8) Number of Central Processing Unit Seconds Ratio/Millions of Instructions Per Second Ratio (Mainframe Services);

(9) Revenues Ratio;

(10) Inventory Ratio;

(11) Procurement Spending Ratio;

(12) Square Footage Ratio;

(13) Gross Margin Ratio;

(14) Labor Dollars Ratio;

(15) Number of Personal Computer Work Stations Ratio;

(16) Number of Information Systems Servers Ratio;

(17) Total Property, Plant and Equipment Ratio;

(18) Generating Unit MW Capability Ratio;

(19) Number of Meters Ratio; and

(20) O&M Expenditures Ratio.

In addition to the individual methods listed above, combinations of the above methods are also used. The most widely used combinations are a weighted average of the Number of Customers Ratio and the Number of Employees Ratio and a weighted average of the Gross Margin Ratio, Labor Dollars Ratio, and Total Property, Plant and Equipment Ratio (Three Factor Formula). Other combined methods include, but are not limited to, a weighted average of the Circuit Miles of Electric Transmission Lines Ratio and Electric Peak Load Ratio as well as a weighted average of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio.

Q. What is the rationale behind the selection of these ratios?

A. Consistent with traditional cost causation principles, the ratios represent "cost drivers" for a particular function (*i.e.,* those factors which are the greatest contributors to costs). For example, costs related to support of personal computers are allocated based on the Number of Personal Computer Workstations Ratio. Costs related to meter reading and to customer billing and payment processing in the Marketing and Customer Relations Function are allocated based on the Number of Customers Ratio. For some functions, costs of a general nature are allocated based on a weighted average of more than one ratio, as discussed above. The DEBS Service Agreement describes how the weighted-average ratios are calculated.

Q. Under what circumstances are the allocation ratios set forth in Appendix A of the DEBS Service Agreement used to determine charges to DEF?

A. The allocation ratios provided in Appendix A of the DEBS Service Agreement are used to assign charges to client companies, including DEF, for activities that cannot be charged directly. For example, costs associated with the human resources function are allocated to the client companies, including DEF, using the Number of Employees Ratio as provided in the DEBS Service Agreement.

Q. What processes do DEBS employees follow in allocating their time and expenses?

A. All source documents (*e.g.*, time records, expense accounts, and journal entries) applicable to DEBS require a special input code based on the applicable operating unit ("OU"). The initiating department determines the appropriate OU for each transaction. The specific OU

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indicates whether the cost should be directly assigned, distributed, or allocated, and it also determines the appropriate percentage allocation to be used for those costs that are allocated. Using the OU, the accounting system will process each transaction and assign the appropriate costs to each respective client company. For the allocable OUs, the percentage allocated to each client company is determined periodically, at a minimum on an annual basis, by way of a cost study.

Q. Do the utility-to-utility allocations work the same way?

A. Yes, the utility-to-utility allocations work the same way and use some of the same allocation factors as the service company allocations. A large portion of the employees are Carolinas' utility employees (*i.e.*, Duke Energy Carolinas and Duke Energy Progress), but they support the entire enterprise from a functional standpoint. Common costs for these functions are allocated by a utility-to-utility allocation. It should be noted that employees are instructed to direct charge whenever possible, and to not default to the allocation pool, which would result in inappropriate costs being allocated to DEF. Duke Energy conducts an internal audit of utility-to-utility allocations twice a year to determine compliance with applicable service requests.

Q. Please describe further the cost study used to determine the allocation percentages.

A. Annually during the budget cycle, DEBS conducts a cost study, applying the applicable data to the allocation ratios described in Appendix A to the DEBS Service Agreement. From these cost studies, DEBS updates the allocation percentages of each allocable OU to reflect the current underlying foundation of the allocation ratios. For example, the OU based on the number of employees, which is primarily utilized by the human resources function within DEBS, is updated annually to reflect the number of employees of each of DEBS' affiliate companies. These same calculations are then used during the actuals period for which the budget was prepared. For the test periods at issue in this proceeding, the Company used the cost study developed for 2023.

IV. <u>CONCLUSION</u>

Q. Did you provide any information to other witnesses for their use in this proceeding?

A. Yes, I supplied Company witness Michael O'Hara with the DEBS and Utility allocation factors and loading rates as well as the A&G O&M in effect for his use in developing the forecasted financial data. Through the budgeting process, I received information from Company witness Shannon Caldwell regarding budgeted benefits and incentives. Benefits, incentives, and other labor loadings were calculated based on this information. My team also prepared the data used for allocations of the service company allocations and utility-to-utility allocations where applicable. Under the DEBS Service Agreement and Utility Service Agreement discussed above, allocations were then calculated based on this information. This information was then provided and used for the Forecasted Test Years.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

(Transcript continues in sequence in Volume 2.)

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 4th day of September, 2024.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028