Dianne M. Triplett
DEPUTY GENERAL COUNSEL

July 2, 2024

VIA ELECTRONIC MAIL

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

Re: *Docket 20240025-EI, Petition for Rate Increase by Duke Energy Florida, LLC*

Dear Mr. Teitzman,

Please find enclosed for electronic filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Rebuttal Testimony and Exhibit BMHB-7 of Benjamin M. H. Borsch.

Thank you for your assistance in connection with this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully submitted,

/s/Dianne M. Triplett

Dianne Triplett

DMT/mh

Attachments

CERTIFICATE OF SERVICE

Docket No. 20240025-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 2nd day of July, 2024, to the following:

/s/ Dianne M. Triplett
Dianne M. Triplett

Jennifer Crawford / Major Thompson / Shaw Stiller Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 JCrawfor@psc.state.fl.us MThompso@psc.state.fl.us SStiller@psc.state.fl.us	Walt Trierweiler / Charles J. Rehwinkel / Mary Wessling / Austin Watrous Office of Public Counsel 111 W. Madison St., Rm 812 Tallahassee, FL 32399 rehwinkel.charles@leg.state.fl.us trierweiler.walt@leg.state.fl.us watrous.austin@leg.state.fl.us wessling.mary@leg.state.fl.us	James W. Brew / Laura Wynn Baker / Sarah B. Newman Stone Mattheis Xenopoulos & Brew, PC PCS Phosphate-White Springs 1025 Thomas Jefferson Street, NW Suite 800 West Washington, DC 20007-5201 jbrew@smxblaw.com lwb@smxblaw.com sbn@smxblaw.com
Jon C. Moyle, Jr. / Karen A. Putnal Moyle Law Firm, P.A. FIPUG 118 North Gadsden Street Tallahassee, Florida 32301 jmoyle@moylelaw.com kputnal@moylelaw.com	Bradley Marshall / Jordan Luebkemann / Hema Lochan Earthjustice LULAC & FL Rising 111 S. Martin Luther King Jr. Blvd. Tallahassee, Florida 32301 bmarshall@earthjustice.org jluebkemann@earthjustice.org hlochan@earthjustice.org flcaseupdates@earthjustice.org	William C. Garner Law Office of William C. Garner, PLLC SACE 3425 Bannerman Road Unit 105, No. 414 Tallahassee, FL 32312 bgarner@wcglawoffice.com
Tony Mendoza / Patrick Woolsey Sierra Club 2101 Webster Street Suite 1300 Oakland, CA 94612 tony.mendoza@sierraclub.org patrick.woolsey@sierraclub.org	Robert Scheffel Wright / John T. LaVia, III Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper, P.A. Florida Retail Federation 1300 Thomaswood Drive Tallahassee, Florida 32308 schef@gbwlegal.com jlavia@gbwlegal.com	Nikhil Vijaykar Keyes & Fox LLP EVgo Services, LLC 580 California St., 12th Floor San Francisco, CA 94104 nvijaykar@keyesfox.com
Sari Amiel Sierra Club 50 F St. NW, Eighth Floor Washington, DC 20001 sari.amiel@sierraclub.org	Peter J. Mattheis / Michael K. Lavanga / Joseph R. Briscar Stone Mattheis Xenopoulos & Brew, PC NUCOR 1025 Thomas Jefferson Street, NW Suite 800 West Washington, DC 20007-5201 pjm@smxblaw.com mkl@smxblaw.com jrb@smxblaw.com	Lindsey Stegall EVgo Services, LLC 11835 W. Olympic Blvd., Ste. 900E Los Angeles, CA 90064 Lindsey.Stegall@evgo.com Frederick L. Aschauer, Jr., Esq. Allan J. Charles, Esq. Lori Killinger, Esq. Lewis, Longman & Walker P.A. AACE / Circle K / RaceTrac / Wawa 106 East College Avenue, Suite 1500 Tallahassee, Florida 32301 fAschauer@llw-law.com acharles@llw-law.com lkillinger@llw-law.com jmelchior@llw-law.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20240025-EI

Submitted for filing: July 2, 2024

REBUTTAL 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. Did you previously file direct testimony in this proceeding?

A. Yes. I submitted pre-filed direct testimony in this docket on April 2, 2024.

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 is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to portions of the direct testimonies of the Office of Public Counsel's ("OPC") Witnesses David E. Dismukes, James R. Dauphinais, and Helmuth Schultz, Florida Rising and League of United Latin American Citizens ("LULAC") Witness Karl Rábago, Florida Industrial Power Users Group ("FIPUG") Witness Jonathan Ly, as well as Sierra Club Witness Rose Anderson.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes, I have prepared or supervised the preparation of Exhibit BMHB-7, the cost-effectiveness analysis for the University of Florida Cogeneration facility. This exhibit is true and accurate, subject to being updated throughout the course of this proceeding.

Q. Please summarize your rebuttal testimony.

A. The Combined Cycle Efficiency ("CCE") Improvements, Solar, and Battery Storage investments proposed in this case are the result of the Company's thoughtful and disciplined efforts to provide clean, safe, reliable, and cost-effective energy to its customers and I am pleased to note that there are several proposals I presented in my direct testimony that the intervenors support. I would like to highlight that OPC agrees that the CCE Improvements and 12 of the 14 proposed solar projects are reasonable and prudent to pursue and FRF Witness Chriss testifies that FRF supports the Company's proposal to expand the Clean Energy Connection program.

In terms of the Load Forecast, I explain that the Company's decision to use the Spring 2023 forecast in the rate case versus the Fall 2023 forecast used in the 2024 Ten-Year Site Plan was a function of the timing when preparing the rate case filing, as further elaborated upon in the testimony of Witness Marcia Olivier. Next, I respond to OPC Witness Dismukes' recommendation to reject the sales forecast as inconsistent with historical trends and explain that while historical trends might inform future conditions and how customers will respond, the forecast is a forward-looking tool that is appropriately based on forecasted assumptions and expectations. I also explain how the Company derived the three out-of-model adjustments that Witness Dismukes testifies are speculative and explain why these adjustments are reasonable and appropriate.

In response to OPC Witness Dauphinais' recommendations regarding the Company's cost-effectiveness analysis, I do not agree with OPC Witness Dauphinais that the CCE projects, solar projects and Powerline BESS are "elective" since they do address a future reliability need which the Company must plan for and develop over a reasonable time period to ensure that it is available. Further, I disagree with his recommendation that the Company should perform an additional cost-effectiveness analysis of 2 of the 14 solar projects. The Company's cost effectiveness analysis appropriately considers these resources together instead of on an individual basis based on how this resource type capacity affects its system. DEF Witness Vanessa Goff responds to FIPUG Witness Ly's recommendations concerning customer protections the Commission should require for the solar projects and why those are not appropriate and should be rejected. I also explain how Witness Dauphinais' recommendation that the Commission should require benefit cost ratios of 1.15 or higher for these projects is completely arbitrary and inconsistent with how the Company develops its proposed resource mix to best operate its system.

Next, I address Florida Rising and LULAC Witness Rábago's recommendations regarding the University of Florida Cogeneration facility and explain the benefits that facility provides to all customers. I explain how the Clean Energy Connection program expansion, which FRF supports, delivers value to our customers who encourage and support the Company expanding its solar portfolio and want access to solar resources but may not have the ability to install solar at their premises. I also explain why the Company pursued the Vision Florida projects, how we have complied with the terms of 2021 Settlement Agreement approved by this Commission regarding this program, and how these projects provide additional qualitative benefits that are not captured in a quantitative cost-effectiveness analysis. Similarly, I support the inclusion of the Powerline Battery Energy Storage System and the value it provides to the Company's resource mix.

I also respond to Sierra Club Witness Rose Anderson's recommendations regarding the retirement date of Crystal River Units 4 and 5 and why the Company has determined that pursuing Department of Energy funding in order to retire these units is not in the best interest of our customers. Finally, I respond to OPC's recommendation that the Levy Land should be removed from Plant Held for Future Use and elaborate on the future uses of this property including the fact that it is part of an Energy Community under the Inflation Reduction Act and potentially eligible for tax credits to deliver even greater value to our customers.

II. <u>REASONABLENESS OF LOAD FORECAST</u>

Q. Please explain why DEF used the Spring 2023 Load Forecast for its rate case filing instead of the Fall 2023 forecast used in the 2024 Ten Year Site Plan.

A. DEF produces two load forecasts each year, one in the Spring and one in the Fall.[1] The Spring 2023 load forecast was the most current at the time of DEF's 5-year financial forecast that was used to develop the Minimum Filing Requirements ("MFRs") filed in this rate case.[2] DEF acknowledges that the Fall 2023 forecast had higher estimated sales in the 2025-2027 rate case test periods than the Spring 2023 forecast.[3] Accordingly, DEF filed a Notice of Identified Adjustments to its rate case filing on June 6, 2024.

Q. Please explain the forecasts used in the rate case filing and how they compare to the load forecast used in the 2024 Ten Year Site Plan.

A. As discussed in my direct testimony, the Spring 2023 forecast was prepared at a time of significant economic uncertainty. Interest rates had risen rapidly as the Federal Reserve sought to contain increasingly high rates of inflation. The forecast of economic activity in the Moody's Analytics Winter Report called for decreased Gross Domestic Product ("GDP") growth and higher unemployment. The forecast prepared in the Fall of 2023 and used in DEF's 2024 Ten-Year Site Plan relied on Moody's 2023 Summer forecast and was prepared at a time when

[1] STF ROG 1-2.
[2] *Id.*
[3] *Id.*

the economic outlook had improved significantly. Neither a significant dip in GDP nor a jump in unemployment had materialized. Economic growth was continuing at a steady pace. Moreover, decreasing inflation rates signaled that the increase in interest rates had peaked or nearly peaked, providing greater certainty in the economic landscape. All these factors resulted in both a higher forecast for 2024, and a modestly greater forecast of retail load growth.

Q. Are there material differences between the results of the Spring 2023 Load Forecast and the Fall 2023 Load Forecast?

A. Yes. Projected Total Retail Sales in the Company's Spring 2023 Load Forecast are lower than projected in the Company's Fall 2023 Load Forecast due to lower sales in the Residential and Commercial classes.

The economic drivers contributing to the Residential sales forecast are average household size and real median income. The 10-year compound annual growth rate ("CAGR") from 2018-2027 for average household size was 1.72% in the Spring 2023 Load Forecast vs 1.79% in the Fall 2023 Load Forecast. The 10-year CAGR from 2018-2027 for real median income was 0.45% in the Spring 2023 Load Forecast vs 0.5% in the Fall 2023 Load Forecast. Another major driver was the difference in the Solar Forecast. On average, the Spring 2023 Load Forecast assumed ~315 GWH more solar annually than the Fall 2023 Load Forecast. The previous 12 months of actual billed sales was 0.24% lower in the Spring 2023

Load Forecast vs the Fall 2023 Load Forecast. As a result of this difference in actuals, the Fall 2023 Load Forecast also began at a higher base value than the Spring 2023 Forecast.

The economic drivers contributing to the Commercial sales forecast are real non-manufacturing GDP, commercial employment, and real retail sales. The 10-year CAGR from 2018-2027 for real non-manufacturing GDP was 2.94% in the Spring 2023 Load Forecast vs 3.04% in the Fall 2023 Load Forecast. The 10-year CAGR from 2018-2027 for commercial employment was 1.63% in the Spring 2023 Load Forecast vs 1.63% in the Fall 2023 Load Forecast. The 10-year CAGR from 2018-2027 for real retail sales was 2.85% in the Spring 2023 Load Forecast vs 2.90% in the Fall 2023 Load Forecast. The previous 12 months of actual billed sales was 0.10% lower in the Spring 2023 Load Forecast vs the Fall 2023 Load Forecast. As a result of this difference in actuals, the Fall 2023 Load Forecast also began at a higher base value than the Spring 2023 Forecast.

Q. How does the recently completed Spring 2024 Load Forecast compare to the Spring 2023 and Fall 2023 Load forecasts?

A. The Spring 2024 Load Forecast is more consistent with the projections in the Fall 2023 Load Forecast. The Spring 2024 Load Forecast's total retail sales for 2025 are 0.3% higher than the Fall 2023 Load Forecast. The Spring 2024 Load Forecast's total retail sales for 2026 are 0.3% higher than the Fall 2023 Load

Forecast. The Spring 2024 Load Forecast's total retail sales for 2027 are 0.2% higher than the Fall 2023 Load Forecast.

A. ***<u>Sales Forecast</u>***

Q. Do you agree with OPC Witness Dismukes' assertion that the Company's Load Forecast is inconsistent with historical trends?

A. No. The historical 10-year CAGR for total retail sales is 1.03%. It is unclear how Witness Dismukes arrived at the historical trend value of 1.1%. It is also important to note that the historical trend is not linear and by recommending a linear growth trend, Witness Dismukes ignores the data his recommendation is based upon. Furthermore, it is not logical to critique the forecasted growth from 2024-2027 based on a historical 10-year trend, especially since in the short-term, economic drivers are under the influence of high interest rates and inflation. If we compare the historical 10-year growth rate from 2014-2023 and the forecasted 10-year CAGR from 2024-2033, we can see that the Spring 2023 forecasted 10-year CAGR is 0.85% and the Fall 2023 forecasted CAGR is 1.19% vs the historical 10-year CAGR of 1.03%. Of course, the years of interest are the test years 2025-2027, therefore, a more reasonable comparison to historic trends would be to look back at the 4-year CAGR from 2016-2019 (before the impacts of COVID-19, i.e., "normal conditions") and compare that growth rate to the forecasted 4-year growth rate from 2024-2027. In that case we can see that the Spring 2023 4-year CAGR is 0.15% and the Fall 2023 CAGR is 0.45% vs the historical 4-year CAGR of 0.35%. In both comparisons, the Fall 2023 Forecast has a higher compound annual growth rate than the historical trend without removing the out of model adjustments for energy efficiency, electric vehicle adoption, and rooftop solar adoption. Lastly, in terms of historical annual year-over-year growth in total retail sales, over the last ten years only three years exceeded 1.0% growth over the previous year, one occurring during COVID-19 and the other two during normal conditions.

Q. In your opinion, when forecasting future conditions is it more appropriate to base those forecasts on past conditions or future anticipated conditions?

A. While historical factors can be helpful in assessing how customers have responded to certain conditions in the past, given the forward-looking nature of forecasts and projections, it is most appropriate to focus on assumptions regarding forward-looking customer behavior expectations and economic conditions. For example, historical trends do not encompass the effects of a recession as was incorporated into the Company's Spring 2023 forecast assumptions. Both historical and future conditions influence the statistically adjusted end use models. Historical sales, weather, and economic drivers are used. The historical variables interact with each other, and their relationships are established. Based on these historical relationships, projected independent variables estimate future sales.

Q. Do unanticipated events such as the COVID-19 global pandemic impact the Company's load forecast results?

A. Yes, absolutely. The COVID-19 pandemic was completely unforeseen and the resulting supply chain constraints and economic impacts of the global pandemic significantly impacted the Company's forecasts at the time. Unpredictable events such as the pandemic create volatility and uncertainty which makes it difficult to accurately predict future activity especially when encountering an event such as a global pandemic. Thus, it is inherently unfair and misleading for Witness Dismukes to incorporate those years into his criticisms of the Company's forecasting processes. Witness Dismukes also criticizes the fact that the Company's 2024 forecast shows a decrease in usage per customer ("UPC") of over two and a half times greater in absolute value than usage changes attributable to new customer growth.[4] Witness Dismukes points out that such an outcome has not occurred since 2012 in the aftermath of the last recession of 2008-2009.[5] This is an interesting criticism given Witness Dismukes' heavy reliance on historical trends, as he completely ignores that the forecasted results for 2024 (which is three to four years following the pandemic) are similar to the historical conditions in 2012 (which occurred approximately three to four years following the Great Recession of 2008-2009).

[4] Dismukes at p. 14, ll. 14-16

[5] *Id.* at p. 14, ll. 16-17.

B. <u>Out-of-Model Adjustments</u>

Q. Has the Company made any out-of-model adjustments?

A. Yes. The Company made out-of-model adjustments to its sales forecast related to 1) changes in energy efficiency, 2) increases in electric vehicle adoption, and 3) increases in behind-the-meter solar installations.

Q. Please explain why the Company made these out-of-model adjustments.

A. While small amounts of energy efficiency, electric vehicle adoption, and behind-the-meter solar are embedded in historical sales, it is important to consider they are not growing linearly. Therefore, it is essential to forecast the incremental growth of these impacts and add them to the base forecast. For example, in the Spring 2023 Load Forecast, by 2027, sales from electric vehicle adoption are expected to exceed 500 GWH, a load equivalent to our largest industrial customers. DEF must account for this load in order to ensure it meets this future demand.

Q. Do you agree with OPC Witness Dismukes assertion that the Company's out-of-model adjustments are "subjective?"[6]

A. No. The annual energy efficiency ("EE") savings forecast was based on DEF's 2019 Demand Side Management ("DSM") Goals and 2020-2024 DSM Program Plan approved by the Commission. The forecast was developed at the EE

[6] OPC Dismukes Direct Testimony at p. 4, ll. 4-5.

measure-level on an annual incremental and cumulative with-roll-off basis. The cumulative with-roll-off forecast accounts for the effective useful life of each measure. For the years beyond 2024, it was assumed savings would decline by 10% from the average of the prior forecast years up to the maximum five-year rolling average. The forecast also includes an estimate of the potential additional savings associated with the EE rebates and tax credits available through the Inflation Reduction Act. An hourly EE savings forecast was then developed by applying the annual forecast to residential and non-residential load shapes. The hourly EE forecast also assumed that one-twelfth of new annual program savings would occur each month over time.

For electric vehicle ("EV") modeling, the Company used a third-party model (Guidehouse Vehicle Analytics and Simulation Tool ("VAST")) to derive the forecast. As described below, the VAST model specializes in the forecast of EVs. Once this EV forecast is developed it is entered as a direct load modifier to the Company's load forecast. As Witness Dismukes states, these VAST model outputs were provided and show the vehicle electrification impacts to the residential, commercial, and industrial classes.

The VAST tool first develops an EV forecast based on multiple parameters including historical data, such as vehicle registrations (IHS Markit) and forecasted data, such as EV utilization and efficiency characteristics (Argonne National

Lab), projections of fuel costs (from EIA and Automotive Association of America), future EV availability and consumer acceptance (Guidehouse insights), and EV miles traveled (from Federal Highway Administration). These variables, along with others, help determine the total cost of ownership of a vehicle which is used in the development of the forecasted EV adoption. Once the EV adoption forecast is created, the associated energy and load associated are forecasted. Variables to determine energy, such as EV miles traveled and EV efficiency, can be used to calculate charging energy requirements. Associated load charging profiles are then derived from public, private, and third-party analyses. These charging profiles are broken down by three duties: light, medium, and heavy. Based on the adoption forecast, the projected amount of energy needed to charge the EVs, and the hourly EV demand profiles, the jurisdictional EV hourly forecast is developed. All three duties are calculated using similar methodology and make up the EV load forecast added to the Company's load forecast.

The number of behind-the-meter ("BTM") solar photovoltaic ("PV") installations has continued to grow in the Company's service territory over the past several years and this trend is expected to continue. These distributed resources will generate power and whether consumed on site or delivered to the grid, this self-generated energy will act to reduce overall demand. As such, it is important to incorporate the impact in the load forecast. The out-of-model PV adjustments reflect the expected energy to be produced from new BTM solar PV systems starting from the beginning of 2023 as per the Spring 2023 Load Forecast.

The BTM forecasting process uses regression modeling techniques to estimate the relationship between adoptions (installations) and payback. It is an economic view from a customer perspective with payback as the independent variable. Historical data is used to determine the relationship and the resulting regression equation and future payback projections are used to estimate forward adoptions. The number of adoptions is converted to capacity using historical size estimates and then the capacity is converted into energy estimates by applying hourly production profiles.

The primary inputs to the payback model include system cost, incentives, rates, and capacity factors. The system cost data is sourced from Guidehouse. Starting with the cost projections from Guidehouse and applying known incentives such as the Federal Investment Tax Credit (as per the Inflation Reduction Act) yields an estimated base installation cost. Bill savings are then determined based on rates and rate structures as well as expected generation. The payback is calculated as the time required for the monthly bill savings to offset the initial cost of the system.

The hourly production profiles are derived from PV modeling using PVSyst software. Historical irradiance data from 7 locations within the Company service territory is collected and analyzed using a combination of 21 different tilt and azimuth configurations, with the results weighted to produce profiles for both residential and non-residential systems.

C. ***<u>Reserve Margins</u>***

Q. How would you characterize DEF's planning reserve margin and loss of load risk?

A. DEF plans to a minimum 20% reserve margin and reviews the resulting resource plans to assess the loss of load probability. In any given year, the reserve margin may be above the target due to several factors including the natural "lumpiness" of generation additions, especially when large units are added, and the need to prepare for future events including projected load growth and future unit retirements. DEF's reserve margin as projected in the 2023 TYSP, which was the principal planning document in the assessment of the proposed units for this case, shows a Base Case summer peak reserve margin ranging from 28% in 2024 and a high of 36% in 2025 to a low of 20% in 2031 and 2032. The higher reserve margin in the early years is partially reflective of the capacity increases from the CCE projects which are being implemented to reduce fuel consumption and cost in these baseload units. Lower reserve margins later in the plan represent DEF planning to a long-term target, allowing for the retirement of high-cost capacity contracts and older oil-fired units. Planned solar units are built throughout the period, creating a progression toward the long-term transition toward lower consumption of fossil fuels and resulting lower costs.

D. Unresolved Issues

Q. Were there any additional issues with the Company's forecasts or models that OPC noted as unresolved?

A. Yes. Witness Dauphinais noted that OPC had two unresolved issues it was pursuing in discovery. The first was identified as a discrepancy between different peak loads as shown in DEF's modeling and as shown in the TYSP. This perceived discrepancy stems from differences in the way that the demand response is treated in the model versus the Commission-required reporting in the TYSP. DEF has addressed this issue in detail in discovery. The second is not an unresolved issue, but a new request from Witness Dauphinais and by extension OPC that DEF provide additional analysis regarding a subset of the proposed solar portfolio. That issue is discussed in more detail in this testimony.

E. Customer Growth and Proposed Investments

Q. How do you respond to Witness Rábago's assertion that the Company's proposed spending in this case is not commensurate with the level of customer growth the Company is projecting?

A. Witness Rábago's comparison of customer growth rates to percentages of investment spending is misleading and a completely arbitrary and inappropriate "apples-to-oranges" comparison. Customer growth is not the only determinant of the need for generation investment. Load may not be linearly associated with the number of customers. Unit retirement due to age or other factors is another significant driver. New technology or conditions may change the relationship between the number of customers and the electric load. Efficient HVAC or appliances, customer owned solar, or EVs will all change the use per customer and the load shape. The need for new generation is evaluated based on the need to balance available generation with the projected customer load, reliability requirements, and other factors including environmental compliance. DEF Witnesses Ed Scott and Brian Lloyd provide further rebuttal testimony on why the Company's growth-related grid spending levels are reasonable and prudent.

III. COST-EFFECTIVENESS OF SOLAR PROJECTS

Q. Do you agree with OPC Witness Dauphinais that the Company should perform a separate cost effectiveness analysis for two of the solar projects projected to go in-service in 2027?

A. No. The Company does not perform cost-effectiveness analysis on just one or two solar projects. Rather it considers the entire portfolio of solar resources necessary to meet the generation and reliability needs for a particular timeframe. In this case, the 14-project portfolio was developed as a part of the larger need for solar energy across the entire period through 2035 based on an efficient approach to construction, operational integration, and transmission interconnection.

Project or portfolio value in Florida is calculated based on a differential resource plan value. In this way, the value presented represents the interactive total for all the projects – the cumulative capacity of the solar units defers other future CTs, which creates a portion of the value. Witness Dauphinais asserts that the two projects should be studied separately in part based on his estimation of Benefit to Cost ratio. His linear approximation of the benefits does not assess how the cumulative capacity changes the future resource plan.

Q. How do you respond to FIPUG Witness Ly's statement that the Company has overstated gas prices in its cost-effectiveness analysis and should perform more sensitivity analyses?

A. DEF's fuel forecast methodology utilizes both a short-term (spot market) and a long-term (fundamental) view and blends them to create the overall forecast. DEF uses the NYMEX spot price forecast for the first 5 years of a given analysis. For the longer-term forecast, DEF creates an average of several different forecasts including the EIA forecast and forecasts produced by reputable proprietary forecasters. Over years 6 through 8 of the forecast, the NYMEX forecast is linearly blended with the average fundamental forecast so that in year 9 and beyond, the forecast is the average fundamental forecast.

The fuel forecast that was used for the cost-effectiveness analysis was developed in the Fall of 2022 and based on the NYMEX forecast of September 15, 2022. Markets in 2022 were strongly affected by the impacts of the war in Ukraine and the related disruption of oil and natural gas supplies from Russia, which in turn increased prices for liquified natural gas worldwide. In addition, domestic markets continued to be impacted by the supply and demand disruptions caused by the COVID pandemic and the economic recovery from that event. Labor and supply chain disruptions limited domestic supplies while demand was supported by the rapid economic recovery. Taken together, these factors caused a spike in prices across all fuel categories. Although markets had begun to recover by Fall 2022, there was still a persistence of higher pricing in the forecast, particularly in the NYMEX spot market forecast.

The table provided by Witness Ly does not provide an apples-to-apples comparison. DEF's natural gas forecast is developed as described above and includes the variable portion of the transportation costs. The largest difference is the timing of the NYMEX forecasts. As discussed above, the DEF forecast was based on the September 15, 2022 NYMEX spot forecast. Mr. Ly's data comes from projections made in the first half of 2024.

DEF did not perform fuel sensitivity analysis because DEF's low fuel forecast was very close to the mid fuel forecast and would not have provided significant differences; and the high fuel forecast analysis would have been irrelevant since it would have provided even more benefit.

Q. Does DEF agree with Witness Ly that the proposed solar projects do not benefit customers without Production Tax Credit ("PTC") qualification?

A. No. DEF's assumptions include the applicable value of the PTCs, which are established in current law. It is overly simplistic to create a hypothetical case in which the value of the PTCs is simply subtracted from the project value. A new regime without the Inflation Reduction Act ("IRA") would cause many potential changes in the overall market including impacts to the competition for solar PV equipment and construction and impacts to the price of fossil fuels. In addition, Duke Energy continues to believe that in the long term there will be programs constraining the emissions of greenhouse gases, whether through more stringent emissions limits on fossil fuel generators or a penalty for emissions. Under any of these updated assumptions, these solar projects will bring benefits to DEF's customers.

Q. Does DEF agree with Witness Ly that DEF should only recover costs for PTC qualifying projects?

A. No. This recommendation misconstrues the way that the PTC value is created. The PTC value accrues based on the generation of solar energy for the DEF system and is independent of whether the total cost of the installation includes other necessary upgrades such as transmission costs. Such a distinction might be applicable if DEF were expecting to use the Investment Tax Credit option under the IRA, but it is not relevant under the PTC assumption. DEF has included the expected cost of transmission upgrades in the cost benefit analysis to provide a complete understanding of the costs and value to the customers; however, the value of the PTCs is based on the future solar generation and is not based on any subcategorization of the investment costs.

IV. <u>CEC PROGRAM EXPANSION</u>

Q. Do any parties support the Company's proposed expansion of the Clean Energy Connection ("CEC") program?

A. Yes. FRF Witness Chriss testifies that FRF supports the Company's proposal to expand the CEC program.

Q. Several intervenors argue that the Company should not expand the Clean Energy Connection program. How do you respond?

A. DEF's CEC Program is about delivering on what our customers want. It builds on the concept of shared community solar with customers that want to participate in Florida solar advancement, support renewable energy, and measure their environmental contributions. Some customers do not want to or cannot install solar panels at their home or business. The Program provides solar access through a subscription fee, bill credits, and renewable energy certificates based on their subscriptions' portion of actual solar generation. It also allows income-qualified customers to reach solar that might not otherwise.

V. POWERLINE BATTERY ENERGY STORAGE SYSTEM

Q. How do you respond to OPC Witness Dauphinais' recommendation that the Commission should remove the entire cost of the Powerline BESS?

A. Mr. Dauphinais' recommendation is shortsighted. Many factors go into integrated system planning. The careful balance of meeting future needs in a cost-effective manner, optimizing current and planned resources available on the system, and protecting grid reliability all weigh into future grid investments. The Powerline BESS resource solves for planning these factors during the time horizon presented.

VI. VISION FLORIDA

Q. Does Witness Rábago make certain recommendations regarding DEF's Vision Florida Program?

A. Yes. Witness Rábago recommends that the "Commission should disapprove any spending by DEF under the Vision Florida program unless and until DEF demonstrates the merits of such investments through objective, comprehensive, and transparent BCAs that evaluate proposed investments against all reasonable alternatives."[7]

Q. What was the intent of Vision Florida and was Vision Florida approved by this Commission as part of the 2021 Settlement Agreement?

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[7] Rábago Testimony at 36, ll. 6-9.

A. Paragraph 25 of the 2021 Settlement Agreement, which was approved by the Commission, recognized that the electric grid and energy technologies are changing rapidly. To reasonably evaluate evolving technologies on the DEF system, the Company must be able to test or pilot resources that may add to DEF's fuel diversity, provide alternate forms of local generation, test alternate long-duration battery energy storage technologies, and evaluate how distributed energy resources on local circuits may support grid reliability. The Vision Florida pilot projects meet those objectives within the timeframe, costs, and financial structures that were already agreed upon back in 2021.

Q. Do you agree with Witness Rábago's recommendation regarding Vision Florida spend and additional requirements suggested?

A. No. Piloting rapidly changing technology projects under the Vision Florida program is precisely why the Company does not rely solely on the cost-effectiveness of the projects and considers the significant qualitative benefits, results, and experience to be gained from these pilots on the DEF system. Therefore, Witness Rábago's recommendations are not only outside the terms that were set forth, agreed upon, and approved in the 2021 Settlement Agreement, they are inconsistent with the entire purpose of the program.

VII. <u>UNIVERSITY OF FLORIDA COGENERATION</u>

Q. Please describe the University of Florida Cogeneration Plant.

A. The University of Florida ("UF") Cogeneration plant is a firm capacity (50 MW Net Winter and 44 MW Net summer) resource in the DEF generation portfolio, owned and operated by the Company and located on leased land at the University of Florida's main campus in Gainesville, Florida. The plant's power island equipment consists of one General Electric LM 6000PC Sprint Combustion Turbine Generator ("CTG") with supplementary fired Heat Recovery Steam Generator ("HRSG"). It is used as an engineering teaching facility at the university. The electric energy from the CTG is delivered to DEF's local grid and retail customers. The HRSG delivers steam to the university under a separate agreement. Electric service, land lease, and steam sale arrangements were entered into 32 years ago. The land lease was set to expire, and it had a land surrender option on DEF with rights for UF to purchase the Cogen plant. This option would have allowed UF to self-serve its own electric and steam needs. Currently, DEF maintains its long-standing arrangements with UF including the DEF operation and ownership of the plant.

Q. How do you respond to Witness Rábago's recommendation that the Commission should disapprove of any customer-funded spending on the UF boilers and the steam subsidy unless and until DEF demonstrates cost-effectiveness in a BCA?

A. It is important to understand that UF's alternate option and case evaluated involved UF owning a self-service qualifying facility cogeneration unit resulting in a significant loss of retail electric load. It was and is DEF's view that this transaction straightforwardly added value for all customers because of the retention of the retail sales to UF and the impact that would have had on customer rates.

In light of the questions raised, DEF has prepared a cost effectiveness analysis for the UF boilers showing the impact of this investment on the overall system cost. This analysis shows a gross benefit of $89 million before the net impact of the boiler investment and future steam sales. Overall, there is a net CPVRR benefit of $79 million. This analysis was performed using the current assumptions in the 2024 TYSP. A summary of the results is shown in Exhibit BMHB-7. DEF has not included a break-even curve because the investment yields a benefit to customers in every single year for all years studied.

VIII. <u>BENEFIT COST ANALYSIS RECOMMENDATIONS</u>

Q. How do you respond to OPC Witness Dauphinais recommendation that the proposed generation projects are "elective" and therefore should have a minimum benefit cost ratio ("BCR") of 1.15 or 1.25?

A. First, I do not agree that these investments are "elective." As explained in my testimony, these investments are needed to meet the Company's reliability planning criteria and must be developed over a reasonable timeframe in advance to ensure the capacity is available when needed. Second, Witness Dauphinais' recommendation is completely arbitrary and based off of Regional Transmission Organization guidelines for MISO, PJM and ERCOT standards which applies to a completely different function (transmission v. generation), completely different regulatory structure (deregulated v. traditional state-regulated), and completely different type of electric company than DEF ("wires-only" v. a vertically integrated electric utility).[8] Finally, Witness Dauphinais fails to understand how the Company develops its proposed resource mix, which is determined based on the cost-effectiveness of the option and how that potential generation resource fits into the overall resource portfolio to best operate the system. The Commission should reject Witness Dauphinais BCR recommendation for these reasons.

IX. CRYSTAL RIVER NORTH UNITS 4 AND 5

Q. Please provide an overview of the Company's Crystal River North Units 4 and 5.

A. Crystal River Units 4 and 5, collectively referred to as Crystal River North, were constructed in the early 1980's. In 2009, the units were upgraded with flue gas desulfurization and electrostatic precipitation. Together the two units have a capacity of approximately 1,450 MW and comprise approximately 12% of the Company's total firm capacity and play a significant role in meeting load requirements during peak demand periods.

[8] In addition, note that the PJM BCR requirement is for a certain type of transmission project, specifically economic-based enhancements, or expansions. *See* OA, Schedule 6 Sec 1.5 Procedure for Development of the Regional Transmission Expansion Plan (pjm.com), Section 1.5.7 Development of Economic-based Enhancements or Expansions.

Q. What are the current retirement dates for Crystal River Units 4 and 5?

A. The current retirement date for the units reflected in the 2024 Revised TYSP is 2034.

Q. Do these units provide any unique reliability attributes?

A. Yes. Retaining some coal-fired capacity on the system provides several benefits. Coal-fired units provide the ability to store fuel in advance which allows the Company to manage price increase risks and helps to mitigate some of the risks associated with the intermittency of other generation sources such as renewables and risks around natural gas supply. Since DEF's system is heavily dominated by natural gas-fired capacity, the coal units provide valuable fuel diversity, both in terms of reducing our customers' exposure to natural gas price variability and providing a firm fuel supply in the event of natural gas supply curtailment or interruptions. These units are assigned a 100% firm capacity value because they can be available at all hours to generate power as needed.

Q. Has the Company considered options to retire those units any earlier than 2034?

A. In 2020, the Company performed a retirement analysis and determined that 2034 was the appropriate date as an earlier retirement would increase replacement costs and customers would still need to pay for the remaining net book value of the retired CR Units 4 and 5 units. DEF considered both 2026 and 2029 as alternate retirement years. Those analyses also showed it was not cost effective to convert those units to natural gas. While DEF has not performed a formal subsequent analysis, DEF reviews the results of the 2020 analysis periodically to assess whether the input conditions have changed in a way that would materially affect the results. DEF believes that 2034 remains the appropriate date for the retirement of the units.

Q. Are there risks to replacing firm owned capacity with contracted capacity imports?

A. Yes. Of course, there are various system and cost factors, (i.e., the contracting party, their operating and performance history, longevity in the electric industry, and potential for default) that are considered when evaluating capacity imports compared to local Company-owned and operated firm generation, but we only need to review the events from December 2022 involving Winter Storm Elliot to plainly see the risks of imports. This extreme winter weather event resulted in millions of electric customers without power, there were unplanned unit outages, derations, natural gas pipeline curtailments, downed transmission lines, and infrastructure freeze issues. There was no import capacity available to Florida when the rest of the eastern U.S. was experiencing extreme conditions with capacity issues and surging demand. And finally, there is cost risk where any new contracted capacity would need to be negotiated at a lower price than the marginal price of operating the units, or DEF customers would be harmed by overpaying for the capacity.

Q: How do you respond to Witness Anderson's contention that the resource planning process would benefit from a more rigorous consideration of the ability of solar to contribute to resource adequacy during winter?

A. DEF identifies the winter peak hour as the hour ending 8 am in January, an hour that includes very limited solar irradiance. Sunrise in Orlando ranged from 7:14 to 7:18 am; in St. Petersburg from 7:17 to 7:22 am. This hour is identified based on the peak load hours from the historic weather record. Because of the high variability of winter peak weather, DEF focuses its peak load analysis on years in which unusually cold weather drove high loads, resulting in the identification of this hour. While there may be a limited amount of irradiance during this hour, DEF conservatively assumes zero contribution to peak from the solar units during this period. In addition, DEF projects to be a summer planning utility during all years in the ten-year planning period. Therefore, the new generation during this period is driven by summer need and economic energy provision throughout this period.

Q. Do you agree with Witness Anderson's contention that retiring Crystal River Units 4 and 5 as soon as possible, but no later than 2030, will have significant customer benefits?

A. No. As demonstrated in DEF's 2020 retirement study, earlier retirement of

Crystal River Units 4 and 5 would raise costs to customers. Although the Crystal River units require a higher degree of O&M spending than some new alternative units and there are significant fuel savings from new solar units, the additional costs of accelerating new resources, solar for energy and peakers and batteries for peak capacity along with the associated transmission projects that would be required to replace the Crystal River units would raise the cost to customers. DEF has selected the 2034 retirement because it strikes the "sweet spot" of achieving the unit retirement with the associated environmental, operational, and fuel risk benefits while managing the cost impact of the transition to customers and mitigating sudden associated increases.

Q. Why hasn't the Company considered pursuing funding under the U.S. Department of Energy's Energy Infrastructure Reinvestment ("EIR") program to retire Crystal River North Units 4 and 5?

A. The retirement dates for Crystal River North Units 4 and 5 are based on the Company's reliability criteria. 2034 is the earliest date the Company can retire these units without impacting its ability to reliably serve customers. Thus, given DEF's need for firm capacity to meet its reserve margin requirements through 2034, the Company cannot replace the capacity provided by Units 4 and 5 with clean energy resources in advance of that date given the high cost required to replace that capacity with clean energy resources. Put simply, to do so would lead to "rate shock" to customers during a time when the Company and energy industry is already undergoing significant investments to modernize the grid and transition to zero carbon energy resources by 2050. In addition, there are other factors related to the conditions around the EIR funding as discussed further in the rebuttal testimonies of DEF Witnesses Paige Swofford and Karl Newlin that greatly limit the benefits of that funding. Thus, at this time, the Company has determined that pursuit of the EIR funding is not a reasonable and prudent endeavor for the benefit of its customers.

Q. Has the Company considered other clean energy alternatives that could provide more firm capacity than solar to meet the reliability need served by Crystal River Units 4 and 5?

A. Yes. When considering the capacity amount, timing, and maturity of current clean energy technologies that produce little to no greenhouse gas emissions or pollutants to replace 1,410 MW net summer and 1,442 MW net winter capacity, these resources include nuclear, hydropower, wind, solar, and geothermal. Florida lacks significant elevation changes for hydropower, has limited wind speeds for viable wind farms, and has incompatible geology for efficient geothermal heat transfer. As for nuclear – DEF continues to envision that its Levy County property could have potential "new nuclear" use in the 2038-2048 timeframe. This may be an attractive site for the addition of a new "Zero-Emitting Load Following Resource." As such, DEF is exploring next generation nuclear (Small Modular Reactor ("SMR")) technology. The Levy site remains valuable given its access to water, transportation, and transmission and I discuss this further below. Finally, DEF maintains an open renewable standard offer contract available to any renewable power producer that can bring value to our customers. DEF meets with potential clean energy investors to discuss technologies, potential projects, timing, and qualifications.

X. LEVY LAND

Q. The OPC challenges the Company's inclusion of the Levy Land in Plant Held for Future Use ("PHFFU") in this case. How do you respond?

A. As potential land for large scale power development becomes increasingly scarce, the Levy property provides DEF with a valuable opportunity for the development of a new generating station. The presence of key local attributes, water access, transmission access, and if needed access to natural gas supply as well as the existing nuclear site license gives the property a particular value for DEF's customers as an option for a major new generating development when that is needed in the DEF plan. In addition, the Levy property is in a designated Energy Community under the Inflation Reduction Act providing additional benefits for future clean energy development at that site.

Q. Does being in the Energy Community give additional value to the Levy property?

A. Yes. Because the property is in a designated Energy Community DEF's customers would benefit from a 10% bonus on the tax credits for any qualifying clean energy or energy storage investment. Similar to the treatment of the Powerline BESS, this would provide an additional reduction in the effective cost to customers of a battery project from 30% to 40%, assuming prevailing wage provisions are met. In the event that DEF were to build an advanced nuclear plant such as an SMR on the site, this additional credit would likely be worth hundreds of millions of dollars.

XI. <u>CONCLUSION</u>

Q. Mr. Borsch, your rebuttal covers a lot of ground, but did you respond to every contention regarding the Company's Integrated Resource Plan or Load Forecast in your rebuttal?

A. No. Intervenor testimony on these topics involved many pages of testimony and I could not reasonably respond to every single statement or assertion and, therefore, I focused on the issues that I thought were most important in my Rebuttal Testimony. As a result, my silence on any particular assertion in intervenor testimony should not be read as agreement with or consent to that assertion. In addition, the Company reserves the right to file supplemental rebuttal testimony to address any new issues raised by intervenors in the event they file additional supplemental direct testimony or provide discovery responses after the deadline for the rebuttal filing that impact the Company's rebuttal responses.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CPVRR Results: Analysis of Investing in UF Boilers

CPVRR $M	Investing in UF Boiler	Not Investing in UF Boiler	Investing in UF Boiler - Not Investing in UF Boiler-RR
Gen and Transm Capital Costs	$8,871	$8,871	$0
FOM	$5,608	$5,556	$52
Gas Reservation Charges	$3,963	$3,963	$0
Fixed Costs (Savings / Costs)	$18,442	$18,390	$52
PTC	($4,138)	($4,138)	$0
Fuel Costs	$12,890	$12,772	$118
Variable Costs	$1,287	$1,272	$15
Environmental Costs	$39	$39	$0
Variable Production Costs (Savings / Costs)	$14,215	$14,082	$133
Fixed and Variable Costs (Savings / Costs)	$28,520	$28,334	$186
UF Lost Revenue-Electricity (Savings / Costs)	$0	$274	($274)
Gross Benefit (Savings / Costs)	$28,520	$28,608	($89)
UF Lost Revenue-Steam (Savings / Costs)	$0	$20	($20)
Boiler Cost $30M	$29	$0	$29
Final Benefit (Savings / Costs)	$28,549	$28,608	($79)

Negative Values represent Savings of investing in UF Boiler