Dianne M. Triplett
DEPUTY GENERAL COUNSEL

June 24, 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,

On June 11, 2024, the Office of Public Counsel ("OPC") submitted its confidential testimony and exhibits for James Dauphinais to Duke Energy Florida, LLC ("DEF") for review. On June 11, 2024, DEF filed its Notice of Intent to Request Confidential Classification regarding same.

On June 21, 2024, DEF electronically filed its Request Confidential Classification concerning the confidential information contained in Exhibit No. JRD-17 to the Direct Testimony of James R. Dauphinais.

Enclosed for filing is the **redacted** Direct Testimony and Exhibits of James R. Dauphinais.

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

Respectfully,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/mh
Attachments

299 First Avenue North (33701) ▪ St. Petersburg, Florida
Phone: 727.820.4692 ▪ Email: dianne.triplett@duke-energy.com

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 24th day of June, 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
discovery-gcl@psc.state.fl.us

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

Tony Mendoza / Patrick Woolsey
Sierra Club
2101 Webster Street Suite 1300
Oakland, CA 94612
tony.mendoza@sierraclub.org
patrick.woolsey@sierraclub.org

Sari Amiel
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
sari.amiel@sierraclub.org

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

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

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

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

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

William C. Garner
Law Office of William C. Garner, PLLC
SACE
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

Nikhil Vijaykar
Keyes & Fox LLP
EVgo Services, LLC
580 California St., 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.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

KATHLEEN PASSIDOMO
President of the Senate

STATE OF FLORIDA
OFFICE OF PUBLIC COUNSEL

C/O THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
SUITE 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

EMAIL: OPC_WEBSITE@LEG.STATE.FL.US
WWW.FLORIDAOPC.GOV

PAUL RENNER
Speaker of the House of Representatives

June 11, 2024

CONFIDENTIAL DOCUMENT ATTACHED

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

Re: Docket No. 20240025 - EI

Dear Mr. Teitzman,

Please find enclosed for filing in the above referenced docket the **confidential** Direct Testimony and Exhibits of James R. Dauphinais. This filing is being hand delivered to the Clerk's Office and delivered to counsel for Duke Energy Florida, LLC (DEF). Counsel for DEF has agreed to serve a copy of the confidential testimony to all parties who have executed a non-disclosure agreement with DEF.

The testimony and exhibits of Mr. Dauphinais contain information that DEF has asserted to be confidential, and DEF has informed OPC that DEF will file a Notice of Intent to Request Confidential Classification of Mr. Dauphinais' testimony and exhibits. DEF will redact the material it claims to be confidential and file a redacted version of the testimony and exhibits with the Commission. It is our understanding that DEF will provide its request for confidentiality, including the highlighted confidential material and the accompanying detailed justification, in a separate filing. OPC reserves its right to challenge DEF's claims of confidentiality at the appropriate time.

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

Sincerely,

Walter Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No. 093590

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 on this 11th day of June, 2024, to the following:

*Major Thompson
*Shaw Stiller
Florida Public Service Commission
Office of General Counsel
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mthompso@psc.state.fl.us
sstiller@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Matthew R. Bernier
Stephanie A. Cuello
Duke Energy Florida, LLC
106 E. College Avenue, Suite 800
Tallahassee, FL 32301
FLRegulatoryLegal@duke-energy.com
Matthew.Bernier@duke-energy.com
Stephanie.Cuello@duke-energy.com

Robert Pickels
Duke Energy Florida, LLC
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
Robert.Pickels@duke-energy.com

Dianne M. Triplett
Duke Energy Florida, LLC
299 First Avenue North
St. Petersburg, FL 33701
Dianne.Triplett@duke-energy.com

Molly Jagannathan
Melissa O. New
Troutman Pepper, LLC
600 Peachtree Street NE, Suite 3000
Atlanta, GA 30308
Molly.jagannathan@troutman.com
Melissa.butler@troutman.com

**Jon C. Moyle, Jr.
**Karen A. Putnal
Moyle Law Finn, P.A.
118 North Gadsden Street
Tallahassee, Florida 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com

**Bradley Marshall
**Jordan Luebkemann
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, Florida 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org

**Tony Mendoza
**Patrick Woolsey
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
tony.mendoza@sierraclub.org
patrick.woolsey@sierraclub.org

* Not served at this time. One (1) copy of the confidential testimony has been filed with the PSC Clerk's Office under seal, pending confidentiality determination. DEF will serve Staff with a public version as soon as it becomes available.
**Counsel for DEF will serve those parties who have executed a non-disclosure agreement with DEF.

**Hema Lochan
Earthjustice
48 Wall Street, 15th Floor
New York, NY 10005
hlochan@earthjustice.org
flcaseupdates@earthjustice.org

**Robert Scheffel Wright
**John T. LaVia, III
Gardner Bist Law Firm
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

**Sari Amiel
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
sari.amiel@sierraclub.org

**William C. Garner
Law Office of William C. Garner, PLLC
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

**James W. Brew
**Laura Baker
Sarah B. Newman
Stone Mattheis Xenopoulos & Brew
1025 Thomas Jefferson St. NW
Suite 800 West
Washington, DC 20007-5201
jbrew@smxblaw.com
lwb@smxblaw.com
sbn@smxblaw.com

**Peter J. Mattheis
**Michael K. Lavanga
**Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew
1025Thomas Jefferson St. NW
Suite 800 West
Washington, DC 20007-5201
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

**Frederick L. Aschauer, Jr.
**Allan J. Charles
**Lori Killinger
**J. Melchior
Lewis, Longman & Walker, PA
106 E. College Ave, Suite 1500
Tallahassee, FL 32301
fashauer@llw-law.com
acharles@llw-law.com
lkillinger@llw-law.com
jmelchior@llw-law.com

**Lindsey Stegall
EVgo Services, LLC
11835 W. Olympic Blvd., Suite 900E
Los Angeles, CA 90064
Lindsey.Stegall@evgo.com

**Nikhil Vijaykar
Keyes & Fox LLP
580 California Street, 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Wessling.mary@leg.state.fl.us

* Not served at this time. One (1) copy of the confidential testimony has been filed with the PSC Clerk's Office under seal, pending confidentiality determination. DEF will serve Staff with a public version as soon as it becomes available.
**Counsel for DEF will serve those parties who have executed a non-disclosure agreement with DEF.

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for increase in rates
By Duke Energy Florida, LLC
_______________________________ /

DOCKET NO. 20240025-EI

FILED: June 11, 2024

CONFIDENTIAL PER DESIGNATION OF THE COMPANY

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Mary A. Wessling
Associate Public Counsel

Austin A. Watrous
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Suite 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

Table of Contents

LIST OF EXHIBITS

Exhibit JRD-16	Public Non-Voluminous Discovery Responses Cited to by Mr. Dauphinais in his Direct Testimony
Exhibit JRD-17	Confidential Non-Voluminous Discovery Responses Cited to by Mr. Dauphinais in his Direct Testimony
Exhibit JRD-18	Confidential Desposition Transcript Excerpts Cited to by Mr. Dauphinais in his Direct Testimony
Exhibit JRD-19	Deposition Late Filed Exhibits Cited to by Mr. Dauphinais in his Direct Testimony

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20240025-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Florida Office of Public Counsel ("OPC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. In 1983, I graduated from Hartford State Technical College with an Associate's Degree in Electrical Engineering Technology. Subsequently, I completed undergraduate studies at the University of Hartford and was awarded a Bachelor's Degree in Electrical Engineering. I have also completed graduate level courses in the study of power system analysis, power system transients and power system protection through the Engineering Outreach Program of the University of Idaho.

Q. PLEASE DESCRIBE YOUR EXPERIENCE.

A. I have over 39 years of experience in the electric utility industry, which began with the start of my employment as an Engineering Technician in the Transmission Planning Department of the Northeast Utilities Service Company ("NU," now "Eversource Energy") in 1984. In 1990, upon the completion of my undergraduate studies in electrical engineering, I was promoted to the position of Associate Engineer within the Transmission Planning Department. By 1996, I had been promoted to the position of Senior Engineer within the Transmission Planning Department.

In the employment of NU, I was responsible for conducting thermal, voltage and stability analyses of the NU's electric transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions.

In 1997, I joined the firm of BAI. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have been involved with a wide variety of electric power and electric utility issues including, but not limited, to: ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates, and transmission line routing. I have provided expert testimony on all of the foregoing. This expert testimony has been provided to the Federal Energy Regulatory Commission ("FERC") and the utility regulatory bodies of 21 states or provinces, including the Florida Public Service Commission ("Commission" or "FPSC"). I provide further information on my education and background in Appendix A to my testimony.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. During my employment with NU, prior to the implementation of FERC Order Nos. 888 and 889, the transmission planning organization within whom I was employed was integrated with, and part of, the same functional organization as NU's generation planning organization. This integration led to significant involvement by transmission planning, including myself, in resource planning analyses (e.g., the analysis of the potential net benefit of retirement of existing generation resources) and resource planning in transmission planning analyses (e.g., whether to proceed with economic transmission upgrades). In addition, while employed at NU, I made significant usage of the General Electric Company Multi-Area Production Simulator ("MAPS") to analyze the generation production costs associated with various transmission operating and planning alternatives on the NU system.

Subsequently, during my employment with BAI since 1997, I have become further involved with resource planning issues, initially in support of my colleagues at BAI and later in a lead position. This work has included the review of electric utility resource plans, the review of proposed certificates of public convenience and necessity for new electric utility generation resources, the forecasting of future market prices, the forecasting of future utility rates and the evaluation of long-term power supply options. I have conducted this work both for intervenors in regulatory proceedings and specific retail end-use customer clients of BAI who were evaluating their future power supply options. I have also been extensively involved in the development of Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") - administered power markets including, but not limited to, issues related to markets for energy, operating reserves and capacity.

Q. PLEASE IDENTIFY SOME OF THE CASES IN WHICH YOU PROVIDED TESTIMONY WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. In the past 19 years, I have provided testimony on resource planning and/or the prudency issues related to resource planning in Indiana Utility Regulatory Commission

("IURC") Cause No. 42643, Louisiana Public Service Commission ("LPSC") Docket No. U-30192, IURC Cause No. 43393, IURC Cause No. 43396, Colorado Public Utilities Commission ("CPUC") Docket Nos. 09A-324E and 09A-325E, IURC Cause No. 43956, IURC Cause No. 44012, New Mexico Public Regulatory Commission ("NMPRC") Case No. 13-00390-UT, NMPRC Case No. 15-00261-UT, NMPRC Case No. 17-00174-UT, NMPRC Case No. 19-00018-UT, NMPRC Case No. 19-00195-UT, NMPRC Case No. 21-00083-UT, NMPRC Case No. 23-00353-UT, Michigan Public Service Commission ("MPSC") Case No. U-21090, MPSC Case No. U-21193, FPSC Docket Nos. 160186-EI and 160170-EI (with respect to Scherer Unit 3 in the 2016 Gulf Power Company base rate case), and FPSC Docket No. 20190061-EI (with respect to Florida Power & Light Company's SolarTogether Program and Tariff).

In a number of these proceedings, I had extensive involvement in the review of the utility's Aurora XMP®, EnCompass® or Strategist® resource planning analysis. In the case of EnCompass® and Strategist®, this has included either me personally running the modeling tool or having modeling runs performed under my direction and supervision by other members of the BAI team, based upon data provided by subject utility.[1] As discussed in the Direct Testimony of Duke Energy Florida, LLC ("DEF"

[1] Strategist®, which includes a module called Proview®, is a computer software tool produced by Ventyx that allows resource planners to examine a very large number of alternative resource portfolios with the goal of identifying through an optimization algorithm the most cost effective resource portfolio for an electric utility. It can also be used in a probabilistic mode to test the robustness (i.e., risk) of specific resource portfolios over a wide range of assumption variations. Strategist® is currently utilized, and has been utilized in the past, by many electric utilities to conduct their resource planning. Other commercial software tools that have some or all of the functionality of Strategist® include software tools such as System Optimizer®, PLEXOS®, Aurora XMP® and EnCompass®. Of these, Aurora XMP®, PLEXOS® and EnCompass® have become more commonly used in recent years due to their greater functionality and more robust solution technique.

or "Company") witness Borsch, DEF uses EnCompass® to support its Integrated Resource Planning ("IRP") process.[2]

Q. PLEASE EXPAND ON YOUR PREVIOUS EXPERIENCE WITH THE ENCOMPASS MODELING TOOL THAT DEF USES IN ITS IRP PROCESS?

A. I have received past training for EnCompass® from its vendor, Anchor Power Solutions, and have personally run EnCompass® for resource optimization and production cost analysis for testimony I have presented before the NMPRC and MPSC.

Q. DO YOU HAVE PREVIOUS EXPERIENCE WITH STOCHASTIC LOSS OF LOAD PROBABILITY ("LOLP") ANALYSIS THAT IS COMMONLY USED TO EVALUATE THE RESOURCE ADEQUACY OF ELECTRIC UTILITIES?

A. Yes. I have received past training with respect to SERVM® – a software modeling tool that was developed by Astrapé Consulting to perform LOLP analysis. SERVM® is used by many utilities for LOLP analysis. In addition, I have had members of the BAI staff perform SERVM® runs under my direction and supervision for testimony I have presented before the NMPRC. Also, SERVM® is the primary modeling tool used by the Midcontinent Independent System Operator, Inc. ("MISO") for the capacity accreditation and Loss of Load Expectation ("LOLE") analysis it presents to the MISO Resource Adequacy Subcommittee and the MISO Loss of Load Expectation Working Group, both of which I regularly attend as a representative of

[2] Borsch Direct at 17.

large end-use customer groups located in Illinois, Indiana, Louisiana, Michigan and Texas.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS DOCKET?

A. I present testimony with respect to the prudence, reasonableness, and cost effectiveness of DEF's already incurred and proposed investments for the following supply-side resource projects:

- DEF's currently estimated $154.9 million investment in Combined Cycle Generation Efficiency Improvement Projects ("CCE Projects") that are currently expected to be fully completed by the end of 2026.[3,4]
- DEF's currently estimated $1.663 billion investment in 14 proposed new 74.9 MW_{AC} solar photovoltaic generation facilities that are currently projected to enter service between 2025 and 2027 ("2025-2027 Solar Projects").[5]
- DEF's currently estimated $164.5 million investment in its proposed Powerline 100 MW, 2-hour Battery Storage facility that it projects to enter service in 2027 ("Powerline Battery Project").[6]

DEF's 2024 Ten-Year Site Plan ("TYSP") estimate of the total firm capacity that would be provided by these projects is summarized below.

[3] Anderson Exhibit RDA-3 and DEF Response to OPC ROG No. 118 (Amended on June 7, 2024).
[4] When I use the words "current" and "currently" in this direct testimony, it means current or currently as of the filing date of this direct testimony based on the latest information provided by DEF through discovery and depositions.
[5] DEF Response to OPC ROG No. 118 (Amended on June 7, 2024) and Confidential DEF Response to OPC ROG No. 186.
[6] Jacob Direct at 5.

TABLE JRD-1

<u>Estimated Total Firm Capacity</u>
(MW)

	Summer	**Winter**
CCE Projects	389	347
2025-2027 Solar Projects	262	0
Powerline Battery Project	90	90

Source: DEF 2024 TYSP, April 22, 2024 at Schedule 8

Collectively, these projects represent the largest driver of the increase in DEF's rate base in its three proposed projected test years for this base rate proceeding (calendar years 2025, 2026 and 2027).

Note that the scope of my direct testimony does not go toward the issue of whether DEF should be permitted to have multiple projected test years or to the proper level of projected capital expenditures for the CCE Projects, 2025-2027 Solar Projects or the Powerline Battery Project that should be utilized in each proposed projected test year for setting base rates for those projected test years. Those are extremely important questions in this proceeding as they present a serious risk of over-recovery particularly with respect to DEF potentially later delaying its projected investments, later delaying the projected in-service date of its projected investments, or ultimately not even making its projected investments. These issues are addressed by other OPC witnesses besides myself. My direct testimony instead concentrates on whether these investments once they enter service should be allowed to be reflected in projected test year revenue requirements at all assuming the Commission grants DEF rates based on three projected test years.

Finally, the fact that I do not address any other particular issues in my testimony or am silent with respect to any portion of DEF's Petition or direct testimony in this proceeding should not be interpreted as an approval of any position taken by DEF.

Q. WHAT DID YOU REVIEW PRIOR TO PREPARING YOUR DIRECT TESTIMONY?

A. I reviewed DEF's petition in this proceeding along with the direct testimony in this proceeding of DEF witnesses Olivier, Panizza, Goff, Jacob, Anderson, Borsch, and Seixas. I have also reviewed DEF's responses to discovery in this proceeding regarding the issues of resource planning, Investment Tax Credits ("ITCs"), Production Tax Credits ("PTCs"), the CCE Projects, the 2025-2027 Solar Projects and the Powerline Battery Project. I also listened to, or reviewed the transcription of, the May 2024 depositions in this proceeding of DEF witnesses Goff, Jacob, Anderson and Borsch. Finally, I reviewed the 2023 TYSP and 2024 TYSP of DEF.

Q. BEFORE YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS, DO YOU HAVE ANY CAVEATS YOU WOULD LIKE TO PUT ON THEM?

A. Yes. The compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's petition. With respect to my particular review of the Company's petition, direct testimony and exhibits, and responses to discovery, I have been left with two unresolved issues at the time of the filing of this direct testimony.

The first relates to a discrepancy between the peak demand, coincident peak demand and available capacity in DEF's EnCompass® modeling runs versus what is reported in DEF's TYSPs. This discrepancy exists even though there appears to be no similar discrepancy with respect to annual energy.

The second unresolved issue pertains to the lack of a cost-effectiveness analysis, including Cumulative Present Value Revenue Requirement ("CPVRR") benefit to cost ratio and breakeven calculations, for the latest two of the fourteen solar projects DEF has proposed in this proceeding.

Both of these unresolved issues are continuing to be pursued by OPC in discovery of DEF. The results of that additional discovery may lead to one or more changes to my conclusions and recommendations within this testimony. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these unresolved issues and the effects of those unresolved issues, if necessary.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. With the caveats I have given, my conclusions and recommendations can be summarized as follows:

- DEF's CCE Projects, 2025-2027 Solar Projects and Powerline Battery Project each provide firm capacity to DEF nearly three years earlier than necessary for resource adequacy and as such are not necessary for reliability at this time;

- Therefore, they are elective rather than mandatory for their projected in-service dates;

- In order for the pursuit of generation-related projects such as these that are elective to be prudent and reasonable, they need to be otherwise shown consistent with providing reliable electric service at lowest reasonable cost;

- This requires a demonstration that the projects are for the purpose of serving DEF's customers – not off-system sales – and that there is a robust, essentially "no regrets," economic case for them;

- The demonstration of a robust economic case is required because DEF's customers do not take service from DEF in order to participate in speculative investments but rather to receive reliable electric service at lowest reasonable cost;

- The demonstration is also necessary to ensure the balance of risk for the subject investments is reasonably balanced between DEF and its customers;

- While the CCE Projects are not necessary for reliability at this time, my review of DEF's cost effectiveness analysis shows these projects are for the purpose of serving DEF's customers and are reasonably forecasted to provide a very robust net benefit such that DEF's decision to pursue them with 2023 through 2026 in-service dates was prudent and reasonable;

- While the 2025-2027 Solar Projects are not necessary for reliability at this time, my review of DEF's cost effectiveness analysis shows that 12 of these 14 projects are for purpose of serving DEF's customers and are reasonably forecasted to provide a robust net benefit such that DEF's decision to pursue these 12 projects with 2025 through 2026 in-service dates was prudent and reasonable;

- There is evidence to suggest the forecasted net benefit for the remaining two 2025-2027 Solar Projects is not robust such that DEF's decision to pursue them may not be prudent and reasonable – additional cost-effectiveness analysis needs to be performed by DEF before it can be found that DEF's decision to pursue them with a projected 2027 in-service date was just and reasonable;

- Until it can be found DEF's decision to pursue the last two 2025-2027 Solar Projects with a 2027 in-service date was prudent and reasonable, DEF's decision with respect to the two projects should be deemed not prudent or reasonable and the projected costs for the two projects be entirely removed from DEF's proposed projected test years in this proceeding;

- The Powerline Battery Project is not necessary for reliability at this time and DEF's cost effectiveness analysis shows that it is not forecasted to provide a robust economic benefit such that there is a significant risk it could result in a net cost rather than a net benefit;

- As a result, DEF's decision to pursue the Powerline Battery Project with a projected 2027 in-service date was not prudent or reasonable;

- Therefore, the projected costs for the Powerline Battery Project should be entirely removed from DEF's proposed projected test years in this proceeding.

II. TIMING OF DEF'S FIRM CAPACITY NEED

Q. PLEASE EXPLAIN HOW YOU REVIEWED THE PRUDENCE, REASONABLENESS AND COST-EFFECTIVENESS OF DEF'S ALREADY INCURRED AND PROJECTED INVESTMENTS FOR ITS CCE PROJECTS, 2025-2027 SOLAR PROJECTS, AND POWERLINE BATTERY PROJECT.

A. I started by examining the timing of DEF's forecasted need for additional firm generation capacity and then examined DEF's forecasted economic performance for each of the investments.

Q. PLEASE EXPLAIN HOW THE TIMING OF DEF'S NEED FOR ADDITIONAL FIRM GENERATION CAPACITY AFFECTS THE PRUDENCE, REASONABLENESS, AND COST-EFFECTIVENESS OF DEF'S PROPOSED INVESTMENTS IN THESE PROJECTS.

A. To the extent the firm generation capacity that would be provided by these projects is actually substantially needed immediately, or nearly immediately, following their entrance to service, there is a demonstrated reliability need for the firm capacity provided by them by the end of DEF's projected test years in this proceeding. Under that scenario, the pursuit of them would be consistent with providing reliable electric service at the lowest reasonable cost to DEF's customers provided the projects have a lower Cumulative Present Value Revenue Requirement ("CPVRR") than other alternatives available to DEF that would provide a similar amount of firm generation capacity at a comparable level of risk.

However, if the firm generation capacity that would be provided by the projects is not substantially immediately needed, or nearly immediately needed, the pursuit of the projects in question by DEF with the timing that DEF has proposed would not necessarily be consistent with providing reliable electric service at lowest reasonable cost even if the investments are projected to provide a lower CPVRR for DEF. This is because there is not a reliability justification for the projects that makes them mandatory. Instead, they are elective. As elective projects, it would need to be demonstrated the projects are in fact for the purpose of serving DEF's customers (i.e., not for the purpose of DEF making off-system sales at wholesale). Furthermore, since projected cost savings would be the principal driver of pursuing these elective projects, it also needs to be demonstrated the projected CPVRR net benefit of the proposed projects, over alternatives to them that have an in-service date consistent with the timing of DEF's firm capacity need, is robust enough such that the investments are not speculative in nature and the balance of risk between DEF and its customers for the investments is reasonable.

Specifically, the economic analysis should exclude off-system sales margins (including any Production Tax Credits ("PTC") enabled by off-system sales), the benefit to cost ratio for the investment should be robust (ideally 1.25 or higher, but at least 1.15), and a net CPVRR benefit from the investment be projected to be provided to customers no later than half-way through the life of the investment in question and no longer than 10 years after the investment enters service. The first criterion ensures the projects are being cost justified based on serving the load of DEF's customers rather than speculative off-system sales. The latter two criterion ensure the projects are essentially "no regrets" investments for DEF's customers.

Q. WHY IS IT IMPORTANT THAT DEF'S GENERATION OR RESOURCE INVESTMENTS THAT ARE ELECTIVE, BE "NO REGRETS" INVESTMENTS FOR DEF'S CUSTOMERS?

A. It goes to the issues of the purpose of regulated electric service and the balance of risk between a utility and its customers. DEF's customers are not customers of DEF for the purpose of making speculative investments. They are customers of DEF for the purpose of receiving reliable electric service at the lowest reasonable cost. Hence, any elective investments DEF makes to provide that service need to have a low risk and thus have "no regrets" associated with them. With respect to balancing risk, DEF afforded an opportunity to earn its authorized return on the investments through its base rates whether or not the investments actually provide net savings for DEF's customers. Thus, to keep the balance of risk between DEF and its customers reasonable, the investments made by DEF once again must be of the "no regrets" nature.

Q. WHAT IS THE BASIS OF YOUR 1.25 AND 1.15 BENEFIT TO COST RATIO THRESHOLD?

A. MISO requires a 20-year CPVRR Benefit to Cost Ratio of at least 1.25 for transmission projects pursued as Market Efficiency Projects ("MEP"). These are transmission projects that are solely being pursued for economic reasons.[7] PJM Interconnection, LLC ("PJM") uses the same threshold for economic-based transmission enhancements.[8] ERCOT uses a threshold benefit to cost ratio of 1.15 for such projects.

Q. WHY IS IT IMPORTANT FOR AN EARLY CPVRR BREAKEVEN YEAR TO BE MET IN ADDITION TO MEETING A MINIMUM BENEFIT TO COST RATIO?

A. It complements the minimum benefit to cost ratio by addressing the issue of there being less certainty about the future as you go out in time. There is much more risk with a net benefit actually being realized from a project that is not forecasted to provide a net benefit until many years from now versus one that has a forecast net benefit in just a few years.

Q. PLEASE EXPLAIN HOW DEF CURRENTLY DETERMINES ITS FIRM CAPACITY NEED.

A. DEF applies deterministic and probabilistic criteria to ensure it has sufficient firm capacity, and, thus, resource adequacy, to meet its forecasted load under its

[7] MISO Tariff Attachment FF-Transmission Expansion Planning Protocol Section II (B)(e).
[8] PJM Manual 14B: PJM Region Transmission Planning Process.

TYSPs. The *deterministic* criterion that DEF uses is to carry extra summer and winter firm capacity known as Planning Reserve Margin ("PRM") in an amount equal or greater than 20% of the forecasted firm summer and winter demand of its customers. The *probabilistic* criterion that DEF uses is to carry sufficient extra firm summer and winter capacity to ensure the forecasted LOLP for its firm load is no greater than one loss of load event day in 10 years. DEF's reports its approach is to meet both of these criteria and that it has used this dual reliability criteria approach in its annual TYSPs since the early 1990s. However, it also reports that typically the 20% PRM criterion has triggered resource additions for DEF before the LOLP criterion has become a factor and that a probabilistic analysis is periodically performed to ensure the LOLP criterion is satisfied.[9]

Q. HAS DEF PROVIDED ANY INFORMATION WITH RESPECT TO THE MOST RECENT PROBABILISTIC ANALYSIS THAT HAS BEEN PERFORMED?

A. Yes. DEF indicates it has not prepared a utility of Balancing Authority Area ("BAA") specific LOLP study in the last several years. Instead, DEF indicates that because of the high level of integration of the DEF system into the overall Florida Reliability Coordinating Council, Inc. ("FRCC") system, the extensive use of reserve sharing and the existence of a single reliability coordinator for the state, it is more relevant to evaluate LOLP on a state-wide basis and the FRCC does such an analysis every other year in even numbered years.[10] DEF also reports the most recent FRCC

[9] Borsch Direct at 8-9.
[10] DEF Response to LULAC/FR ROG No. 9.

LOLP study from 2022 reported the following forecasted results for the FRCC region as a whole for 2022 through 2026.[11]

TABLE JRD-2

2022 FRCC LOLP Results

Year	Base Case	No Availability of Firm Imports	No Availability of Demand Response	High Case
	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2022	0.000003	0.000957	0.015117	0.000008
2023	0.000003	0.000441	0.015003	0.000008
2024	0.000002	0.000652	0.014572	0.000009
2025	0.000004	0.000688	0.010994	0.000011
2026	0.000002	0.000597	0.008826	0.000009

Source: DEF Response to LULAC/FR ROG No. 9

Q. THE RESULTS IN YOUR TABLE JRD-2 ABOVE ARE IN TERMS OF DAYS PER YEAR. WHAT DOES THIS TRANSLATE INTO ON A DAYS IN TEN YEARS BASIS?

A. One event day in ten years translates into a LOLP of 0.1 days per year. Thus, the results in Table JRD-2 indicate the FRCC in its 2022 LOLP Study forecasted LOLPs that range from one event day in 500,000 years (for the Base Case for 2026) to one event day in 66.2 years (for No Availability of Demand Response for 2022). These LOLP values are well, well below the one day in ten years target that is the industry

[11] DEF Response to LULAC/FR ROG No. 9.

standard. This suggests the overall FRCC region has large amounts of excess firm capacity, the 20% PRM criterion used by individual Florida utilities such as DEF is more conservative than necessary, or some combination of the two.

Q. WHAT DOES IT MEAN WITH RESPECT TO THIS PROCEEDING?

A. Given DEF's long history of its 20% PRM criterion driving its firm capacity need rather than LOLP study results, the very low forecasted LOLP values being reported for the FRCC region as a whole by FRCC, and DEF's own statements with respect to the tightly integrated nature of the overall FRCC system that DEF is part of, DEF has no need to carry very much, if any, firm capacity in excess of its 20% PRM to maintain a LOLP less than or equal to one day in ten years. The 20% PRM already provides a very large insurance policy to ensure the industry standard one day in ten years LOLP target is met by DEF.

Q. DOES DEF CALCULATE THE FIRM CAPACITY FOR SOLAR GENERATION FACILITIES AND BATTERY STORAGE FACILITIES IN THE SAME MANNER AS IT DOES FOR ITS CONVENTIONAL GENERATION FACILITIES?

A. No. Since they are always available to provide their summer and winter rated capacity in all hours within the bounds startup, shutdown and ramp rate constraints except when on outage, DEF determines the summer and winter firm capacity of its conventional generation facilities based on the summer and winter rated capability of those facilities. However, since solar generation output depends on the presence, level and angle of sunshine and battery storage facilities have limited energy available for discharge, DEF derates the summer and winter firm capacity for these resources from the rated capability of these resources. For solar generation, it has performed an analysis that accounts for the shifting of the time of its net peak in summer as it has higher levels of solar generation penetration.[12] Specifically, DEF arrived at the following estimate of summer firm capacity as a percentage of nameplate capacity for new solar resources as a function of total installed solar generation on its system.

TABLE JRD-3

Solar Firmness	**Solar Up to MWs**
57.0%	1,500
25.0%	2,400
12.5%	3,250
10.0%	5,500

Source: DEF's response to LULAC/FR ROG No. 12

Q. CAN YOU EXPLAIN HOW THIS TABLE WORKS?

A. Yes. The first 1,500 MW of solar generation receives a summer firm capacity of 57% of nameplate. The next 900 MW of solar generation receives a summer firm capacity of 25% of nameplate. Then, the next 850 MW of solar generation receives a summer firm capacity of 12.5% of nameplate, and so on.

[12] The net peak is the peak demand placed on DEF's non-solar resources after accounting for solar generation including retail customer rooftop solar facilities.

Q. HOW MUCH WINTER FIRM CAPACITY IS ASSUMED BY DEF TO BE PROVIDED FROM THE SOLAR GENERATION FACILITIES?

A. None. This is because DEF's forecasted winter peak occurs in darkness.[13]

Q. BASED ON YOUR EXPERIENCE, IS DEF'S APPROACH FOR SOLAR GENERATION UNREASONABLE?

A. Given there is currently very little battery storage capacity or wind generation on the DEF system and the period of interest for this proceeding only involves through 2027 and very shortly thereafter, firm capacity diversity benefits do not need to be considered. Therefore, I cannot say that DEF's approach is an unreasonable approach to properly account for the diminishing value of solar generation toward reducing LOLP during summer periods as the total penetration of solar generation increases.

Q. WHAT APPROACH DOES DEF USE FOR BATTERY STORAGE?

A. Based on a study performed by one of its sister companies in the Carolinas, DEF assumes 90% of nameplate capacity for both summer and winter firm capacity and does so for both two-hour and four-hour storage.

Q. IS THIS A REASONABLE APPROACH?

A. No. A two-hour battery can only provide 50% of its nameplate capacity when discharged over four hours. Given this, DEF should have used a lower percentage of nameplate capacity for two-hour battery facilities, such as its proposed Powerline

[13] DEF Response to OPC ROG No. 75.

Battery Facility, potentially as low as 45% (half of 90%), given its much lesser ability to sustain a discharge at its nameplate capacity versus four-hour battery facilities. I will address this further when I address the forecasted economics of the Powerline Battery Project later in my testimony.

Q. PLEASE EXPLAIN HOW YOU SPECIFICALLY EXAMINED THE TIMING OF DEF'S NEED FOR ADDITIONAL FIRM CAPACITY.

A. I performed an analysis for both DEF's 2023 and 2024 TYSPs. Specifically, I created a modified version of Schedules 7.1 and 7.2 of DEF's TYSP that backs out the summer and winter firm capacity indicated in Schedule 8 of DEF's TYSP that is associated with the CCE Projects, the 2025-2027 Solar Projects, the Powerline Battery Project and the planned resource placeholders that would later enter service that DEF included in its TYSP but is not seeking approval of in this proceeding. I then delayed DEF's planned 2026-2027 retirement in its TYSP of certain combustion turbine generation facilities by three years. With that baseline established, I identified the year when DEF's need for additional firm capacity to meet its 20% PRM first reaches the amount expected in the TYSP from the CCE Projects, then in the amount expected from the TYSP from the 2025-2027 Solar Projects and then finally the amount expected in the TYSP from the Powerline Battery Project. This order reflects the order of the expected in-service dates of these projects.

The results of this analysis, which is summarized in Exhibits JRD-1 through JRD-4 indicates that the summer drives the need for additional firm capacity. In addition, it shows the firm capacity expected from the CCE Projects is not needed until

2029 and the firm capacity expected from the 2025-2027 Solar Projects and Powerline Battery Project is not needed until 2030. Hence, the results of my analysis is as follows:

- The firm capacity expected from the CCE Projects would not be needed until 2029, nearly three years after the last of them is expected to enter service in 2026;
- The firm capacity expected from the years 2025-2027 Solar projects would not be needed until 2030, nearly three years after the last of the projects is expected to enter service in 2027; and
- The firm capacity expected from the Powerline Battery Project would not be needed until 2030, nearly three years after it is proposed to enter service in 2027.

Given these results, the firm capacity that would be provided from these projects would not be needed for reliability shortly after the projects enter service. They would not be needed for reliability until nearly three years past the respective expected in-service dates of the projects. As such, completion of these projects by their projected in-service dates is not necessary for reliability. Hence, the projects at this time are elective rather than mandatory. Therefore, they must be solely justified on the basis of economics, and, as I have discussed, to ensure the projects are consistent with providing reliable electric service at lowest reasonable cost, their economics need to be based on serving DEF's customers, not on off-system sales, and those economics need to be robust.

Q. PLEASE EXPLAIN WHY YOU PERFORMED YOUR DEF FIRM CAPACITY NEED TIMING ANALYSIS FOR BOTH DEF'S 2023 AND 2024 TYSPs AND NOT JUST DEF'S 2024 TYSP.

A. While DEF's direct testimony and exhibits in this proceeding were dated April 2, 2024, the day after DEF initially filed its 2024 TYSP with the Commission, as evidenced by the economic analysis DEF produced in discovery for the CCE Projects, 2025-2027 Solar Projects, Powerline Battery Project, DEF's 2023 TYSP, and DEF witness Borsch's direct testimony, DEF made its initial decision to pursue the CCE Projects, 2025-2027 Solar Projects, and the Powerline Battery Project prior to the development of DEF's 2024 TYSP. Based on my many years of regulatory experience, my understanding is, under the prudence standard, the reasonableness of actions taken, or not taken, by a utility is reviewed based on information known, or knowable, at the time the decision was made. The reasonableness of a utility's actions, or lack of actions, should be judged in light of the circumstances and facts known, or knowable, at the time that the decision was made. Prudence does not permit "hindsight" review of the actions taken. Thus, for that portion of the Company's costs for the projects that were committed prior to its 2024 TYSP, we need to examine DEF's 2023 TYSP since that was available to DEF's decision makers at that time. This said, the 2024 TYSP is relevant with respect to the costs for the projects DEF has not yet committed to incurring.

Q. PLEASE EXPLAIN WHY YOU INCLUDED A THREE-YEAR DELAY OF DEF'S PLANNED 2026-2027 COMBUSTION TURBINE RETIREMENTS IN YOUR FIRM CAPACITY NEED TIMING ANALYSIS.

A. DEF has indicated it has performed no cost effectiveness analysis for those planned retirements, which total to 524 MW of summer firm capacity in the DEF 2023 TYSP and 460 MW of summer firm capacity in the DEF 2024 TYSP.[14] In addition,

[14] DEF 2023 TYSP at Schedule 8 and Confidential Video-Conference Deposition of Borsch, May 30, 2024, Transcript Volume II at 74:9 through 76:21.

while DEF has indicated there is a significant environmental risk need for the Bayboro portion of these facilities, for the rest of these combustion turbines, DEF indicated the trigger mechanism for their planned retirement is DEF being in a period of relatively high reserve margins.[15] Thus, the planned 2026-2027 retirement of the combustion turbine generation in question is predominantly driven by DEF having excess firm capacity – excess firm capacity contributed to by the proposed CCE Projects, 2025-2027 Solar Projects, and the Powerline Battery Project. Therefore, I conservatively assumed DEF would be able to delay the planned retirement of these combustion turbine generation facilities by at least three years if it needed the firm capacity provided by them.

Q. WHAT IF THE BAYBORO PORTION OF THE PLANNED 2026-2027 COMBUSTION TURBINE RETIREMENTS CANNOT BE DELAYED BY AT LEAST THREE YEARS DUE TO THE ENVIRONMENTAL RISK ASSOCIATED WITH THEM IDENTIFIED BY DEF?

A. At the outset, it is important to note that between its 2023 and 2024 TYSPs, DEF has already shown a willingness to delay the retirement of the Bayboro combustion turbines in question by some amount of time as the planned retirement date for them in the 2023 TYSP was December 2025, while in the 2024 TYSP it is now October 2026.[16] Given this, I believe my three-year retirement delay assumption is reasonably applied to the Bayboro combustion turbine units in question.

[15] Confidential Video-Conference Deposition of Borsch, May 30, 2024, Transcript Volume II at 74:9 through 76:21.

[16] DEF 2023 TYSP and 2024 TYSP at Schedule 8.

This said, I have performed a sensitivity analysis with respect to the timing of DEF's capacity need where the planned retirement of the Bayboro combustion turbine units in question is not delayed by three years. The results of this sensitivity analysis, which are summarized in Exhibits JRD-5 through JRD-8, indicate that, if the planned retirement date of the Bayboro combustion turbines in question cannot be delayed by at least three years, the firm capacity provided by the CCE Projects could be needed by DEF as soon as 2027, the year following the last of them entering service in 2026. However, the firm capacity from the 2025-2027 Solar Projects and Powerline Battery Project would continue to not be needed until 2030 – nearly three years after the last of these projects enter service.

Note the changed result with respect to the timing of the need for the firm capacity that would be provided by the CCE Projects would not change my ultimate conclusion in this direct testimony that DEF's decision to pursue the CCE Projects with 2023 through 2026 in-service dates was prudent and reasonable. It would just strengthen my ultimate conclusion for the CCE Projects since the CCE Projects, in addition to being for the purpose of serving DEF's customers and having a very robust economic case for them as I have found, would now also be needed for reliability purposes very shortly after the last of them enters service.

Q. IS THERE ANY ADDITIONAL EVIDENCE SUPPORTING YOUR CONCLUSION THAT THE FIRM CAPACITY THAT WOULD BE PROVIDED BY THE CCE PROJECTS WILL NOT BE NEEDED UNTIL 2029, THAT THE FIRM CAPACITY THAT WOULD NOT BE NEEDED FROM THE 2025-2027 SOLAR PROJECTS WOULD NOT BE NEEDED UNTIL 2030, AND THAT THE FIRM CAPACITY THAT WOULD BE PROVIDED BY THE POWERLINE BATTERY PROJECT WOULD NOT BE NEED UNTIL 2030?

A. Yes. The alternative projects DEF used in its economic analysis of the CCE Projects would not enter service until 2029 and 2033. The alternative projects DEF used in its economic analysis of the 2025-2027 Solar Projects would not enter service until 2030 and 2032. Finally, the alternative projects DEF used in its economic analysis of the Powerline Battery Project would not enter service until 2030 and 2031.[17]

This further substantiates the conclusion of my analysis above that DEF will not need the firm capacity from the CCE Projects, 2025-2027 Solar Projects and Powerline Battery Project until nearly three years after their respective expected project in-service dates given the alternatives DEF utilized would not enter service until nearly three years after the projects DEF was studying.

[17] DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx', '2024 Rate Case Solar Study CPVRR Results.xlsx' and '2024 Rate Case Battery Study CPVRR Results.xlsx'.

Q. PLEASE SUMMARIZE YOUR CONCLUSION WITH RESPECT TO THE ISSUE OF THE TIMING OF DEF'S CAPACITY NEED.

A. The evidence shows that, while DEF uses a combination of deterministic and probabilistic criteria to ensure resource adequacy, in practice its 20% PRM deterministic criterion has alone driven firm capacity additions for DEF. In addition, the FRCC region as a whole has a LOLP of well below the industry standard one event day in 10 years target. As a result, DEF needs very little, if any, firm capacity beyond that necessary to provide it a 20% PRM.

DEF's derate of the rated capability of solar generation when determining the summer and winter firm capacity provided by the same is not unreasonable.

DEF's derate of the rated capability of two-hour battery storage, such as the proposed Powerline Battery project, should be lower than that for four-hour battery storage given only half the rated capability of two-hour battery storage over a four-hour discharge period.

My analysis of DEF's 2023 TYSP and 2024 TYSP shows that DEF does not need the firm capacity that would be provided by its CCE Projects, 2025-2027 Solar Projects and Powerline Battery Projects to meet its 20% PRM criterion for resource adequacy until three years after the respective projected in-service dates of these projects. Given this, they are not required for reliability at the time of their respective in-service dates and thus pursuit of them under their projected in-service dates makes them elective rather than mandatory projects.

For the pursuit of these elective projects to be consistent with providing reliable electric service at lowest reasonable cost, it needs to be shown they will for the purpose of serving DEF's customers (i.e., not to make off-system sales) and that the economic case for them is robust. A robust economic case needs to be demonstrated because DEF's customers are not customers of DEF for the purpose of participating in speculative investments but rather to obtain reliable electric service at lowest reasonable cost. It also needs to be demonstrated to ensure a reasonable balance of risk between DEF and its customers.

To demonstrate a robust economic case, the projects should ideally have a CPVRR benefit to cost ratio of 1.25 or more, but at least no less than 1.15, versus alternatives (with a comparable level of risk that would not enter service until the year DEF needs firm capacity from them) to help ensure the project will in fact ultimately provide a net benefit to DEF customers. In addition, to further ensure this, the projects should break even on a CPVRR basis versus other alternatives (with a comparable level of risk that would not enter service until the year DEF needs firm capacity from them) within half the design life of the projects and in no case less than 10 years after they enter service. All of this will ensure the projects are "no regrets" projects for the purpose of serving DEF's customers such that they are consistent with providing reliable electric service at the lowest reasonable cost.

III. FORECASTED ECONOMIC PERFORMANCE OF THE CCE PROJECTS

Q. YOU HAVE CONCLUDED THE CCE PROJECTS WITH THEIR PROJECTED IN-SERVICE DATES ARE NOT NECESSARY FOR RELIABILITY AT THIS TIME AND THEREFORE MUST BE SHOWN TO BE FOR THE PURPOSE SERVING DEF'S CUSTOMERS, RATHER THAN FOR OFF-SYSTEM SALES, AND HAVE A ROBUST ECONOMIC CASE. HAS DEF PERFORMED AN ECONOMIC ANALYSIS OF THE CCE PROJECTS?

A. Yes. DEF performed a cost-effectiveness analysis for the CCE Projects. The results of it is presented in DEF witness Borsch's Exhibit BMHB-5. The analysis was conducted in 2022 and utilized EnCompass® along with spreadsheet analysis with respect to estimated capital costs. DEF provided copies of the EnCompass® input and output files in response to OPC POD No. 37 and provided the spreadsheets in response to LULAC/FR POD No. 2. I have reviewed these files.

DEF used a 20-year study period ending in 2041 and compared a case with the CCE Projects added to one that instead principally added a 190 MW combustion turbine generation facility in 2029 and a 100 MW battery storage facility in 2033.[18] In the analysis, DEF forecasts a 20-year CPVRR net benefit of $392.827 million, which consists of forecasted gross CPVRR savings of $505.570 million less a forecasted gross CPVRR cost of $112.743 million.[19] This yields a forecasted 20-year benefit to cost ratio of 4.48, which is very robust. The net benefit is derived approximately 58% from avoided fixed generation costs, approximately 30% from reduced fuel and purchased

[18] DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx'.
[19] Borsch Exhibit BMHB-5.

power costs, and approximately 12% from other avoided variable generation costs.[20] Note that while DEF assumed a carbon emission cost in its EnCompass® runs and forecasted a significant carbon emission savings from the CCE Projects based on that cost, DEF has excluded that forecasted amount of savings from its reported forecasted gross savings of $505.570 million and reported a forecasted net benefit of $392.827 million. This is appropriate given there is currently no existing or pending carbon emission tax or cap and trade legislation in Florida or at the federal level. Finally, it should be noted that DEF had negligible off-system sales in both its CCE Projects case and its alternative case. So, the forecasted savings DEF's analysis shows comes from providing service to DEF's customers, not off-system sales.

Q. DID DEF PROVIDE A CPVRR BREAKEVEN CALCULATION IN ITS ANALYSIS?

A. It did not. However, from DEF's spreadsheet files, which included its detailed EnCompass® production cost results, I was able to perform those calculations, which are presented in Exhibit JRD-9. Specifically, the results of DEF's cost effectiveness analysis forecast that the CCE Projects will break even on a CPVRR basis in the second year of the 20-year study period, which is not surprising given the very high forecasted 20-year CPVRR benefit to cost ratio of 4.48.

[20] Borsch Exhibit BMHB-5.

Q. DID DEF PERFORM ANY SENSITIVITY CASES?

A. It did with respect to different possible variations of the CCE Projects it ultimately pursued, but it did not perform any fuel cost or project cost sensitivities.

Q. IN YOUR OPINION, WOULD A FUEL COST SENSITIVITY CASE BE WARRANTED FOR THE CCE PROJECT ANALYSIS?

A. No. The 2022 vintage natural gas and coal prices used by DEF for its CCE Projects cost effectiveness analysis are lower than those for its 2023 TYSP and using higher fuel prices that the one used by DEF would simply yield a greater forecasted net benefit from the proposed CCE Projects.

Q. HAVE THERE BEEN CHANGES TO THE CCE PROJECTS SINCE THEY WERE STUDIED IN 2022?

A. Yes. There have been modifications to the Hines PB 4 Project such that it is now expected to increase the output of Hines PB4 by 80 MW rather than 52 MW.[21] In addition, the projected heat rate reductions have increased for the Citrus PB 1, Citrus PB 2 and Hines PB 4 CCE Projects.[22] Finally, the estimated capital cost of the CCE projects has increased from $124.9 million to $154.9 million.[23]

[21] Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at Assumptions tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and Confidential Deposition of Anderson, May 24, 2024 at response to Late-Filed Deposition Exhibit No. 3.

[22] Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at Assumptions tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx'.

[23] Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at CC_Capital_RR tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx'.

Q. WHAT WOULD BE THE IMPLICATION OF THE GREATER OUTPUT INCREASE FOR HINES PB 4 AND THE INCREASED HEAT RATE REDUCTIONS?

A. Both of these would increase the forecasted gross savings from the CCE Projects versus that forecast by DEF.

Q. ARE ALL OF DEF'S COMBINED CYCLE GENERATION FACILITIES CURRENTLY EXPECTED TO RETIRE BY THE END OF THE 20-YEAR STUDY PERIOD IN 2041?

A. No. For example, the Citrus combined cycle units are assumed to be operational through at least 2058 in DEF's cost effectiveness analysis.

Q. HAVE YOU EXAMINED THE IMPACT IT WOULD HAVE ON THE ECONOMICS OF THE CCE PROJECTS IF THE LATEST CAPITAL COST ESTIMATE FOR THE PROJECTS WAS USED AND THE COMBINED CYCLE UNITS WERE CONSERVATIVELY ASSUMED TO ALL RETIRE BY THE END OF 2041?

A. Yes, I have roughly estimated that impact as a conservative stress test and present it in Exhibit JRD-10. To roughly estimate the impact, I scaled the annual revenue requirement for the original capital cost for the CCE Projects by the ratio of $154.9 million to $124.9 million. Then I added an end effect in 2041 to recover in 2041 the remaining capital cost of CCE Projects that would have been collected from 2042 through 2058. Even under this conservative stress test, the economics for the

CCE Projects are still very robust with a 20-year CPVRR benefit to cost ratio of 3.27 and a CPVRR breakeven in the 3rd year of the 20-year study period.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE CCE PROJECTS?

A. While the CCE Projects are elective rather than mandatory in nature, they are consistent with providing reliable electric service at lowest reasonable cost because their economic justification is based on serving DEF's customers and the projected net economic benefit from the CCE projects is very robust. Therefore, based on my analysis and what I am aware of as the filing date of this testimony, I cannot say that DEF's decision to pursue to CCE Projects was imprudent or unreasonable.

IV. FORECASTED ECONOMIC PERFORMANCE OF 2025-2027 SOLAR PROJECTS

Q. LIKE WITH THE CCE PROJECTS, YOU HAVE CONCLUDED THE 2025-2027 SOLAR PROJECTS WITH THEIR PROJECTED IN-SERVICE DATES ARE NOT NECESSARY FOR RELIABILITY AT THIS TIME AND THEREFORE MUST BE SHOWN TO BE FOR THE PURPOSE OF SERVING DEF'S CUSTOMERS, RATHER THAN OFF-SYSTEM SALES, AND HAVE A ROBUST ECONOMIC CASE. HAS DEF PERFORMED AN ECONOMIC ANALYSIS OF THE 2025-2027 SOLAR PROJECTS?

A. Yes. As with the CCE Projects, DEF performed a cost-effectiveness analysis for the 2025-2027 Solar Projects. The results of this analysis with all 14 of the 2025-2027 Solar Projects pursued, is presented in DEF witness Borsch's Exhibit BMHB-3-Amended. In addition, the results of the analysis with only the first five of the fourteen

2025-2027 Solar Projects being pursued is presented in DEF witness Borsch's Exhibit BMHB-4-Amended.

Q. WHY DID DEF PERFORM A VERSION OF THE ANALYSIS WITH ONLY FIVE OF THE PROJECTS PURSUED?

A. DEF is proposing to pursue the first five of the fourteen 2025-2027 Solar Projects as an expansion of its Clean Energy Connection ("CEC") voluntary community solar program rather than as normal DEF generation projects. DEF witness Borsch in his direct testimony presents the analysis of the five projects alone to show they are cost-effective.[24] However, DEF has indicated, and I have confirmed from my review of DEF's Encompass® input and output files provided in response to OPC's Fourth Request for Production, No. 37 and the relevant spreadsheet files provided in response to LULAC/FR First Request for Production, No. 2, that there is no difference in how the five projects proposed to be an expansion of the DEF CEC program are modeled in the cost-effectiveness analysis versus the other nine of the fourteen 2025-2027 Solar Projects.[25] As a result, the analysis presented by DEF in DEF witness Borsch's Exhibit BMHB-4-Amended does not present any information with respect to the benefit of expanding DEF's CEC program. Rather, it indicates DEF's forecasted cost-effectiveness of pursuing the five projects alone as normal DEF generation projects.

[24] Borsch Direct at 18-20.
[25] Confidential Video-Teleconference Deposition of Borsch, May 30, 2024, Transcript Volume II at 106:24 through 108:12.

Q. HAVE YOU MADE ANY EVALUATION OF THE REASONABLENESS OF DEF'S PROPOSAL TO EXPAND ITS CEC PROGRAM?

A. No, that goes beyond the scope of my analysis and direct testimony in this proceeding. I have not examined the issue and as a result have not developed an opinion on that question for this testimony.

Q. WAS THE COST EFFECTIVENESS ANALYSIS THAT DEF PERFORMED FOR THE 2025-2027 SOLAR PROJECTS PERFORMED IN THE SAME MANNER AS DEF'S COST EFFECTIVENESS ANALYSIS FOR ITS CCE PROJECTS?

A. It was generally performed in the same manner, but there are some important differences. Specifically, it was different in the following respects:

- The analysis was performed in 2023 using DEF's 2023 TYSP assumption including its 2023 TYSP base case fuel price assumptions.[26]
- DEF used a study period that ends in 2057, rather than 2041, based on the last of 2025-2027 Solar Projects entering service in 2027 and an assumed design life for the projects of 30 years.[27]
- The principal assumed alternative resources for the 2025-2027 Solar projects consisted of a 190 MW combustion turbine generation facility added in 2030 and a four-hour 50 MW battery added in 2032.[28]
- DEF included PTCs for the projects under the Inflation Reduction Act ("IRA") assuming it could fully realize 90% of their value in 2025, 2026, and 2027 and 100% of their value thereafter.[29]

[26] Borsch Direct at 10 and 18 and DEF's response to OPC ROG No. 74.
[27] Borsch Direct at 17; DEF 2023 and 2024 TYSPs at Schedule 9; Confidential Deposition of Goff, May 29, 2024, p. 91, lines 4-5; DEF Response to LULAC/FR DOD No. 2 at Solar14_RR tab of '2024 Rate Case Solar Study_14_Solar.xlsx'.
[28] DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case Solar Study CPVRR Results.xlsx'.
[29] Panizza Direct at 9 and DEF Response to LULAC/FR POD No. 2 at PTC tab of '2024 Rate Case Solar Study_14_Solar.xlsx'.

- DEF assumed no cost for carbon emissions.

Q. WHAT WERE THE RESULTS OF DEF'S COST EFFECTIVENESS ANALYSIS?

A. As detailed in DEF witness Borsch's Exhibit BMHB-3-Amended, if all 14 of the 2025-2027 Solar Projects are pursued as proposed by DEF, DEF forecasts a CPVRR net benefit of approximately $552 million, which consists of gross CPVRR savings of approximately $2.478 billion less gross CPVRR costs of approximately $1.925 billion. This amounts to a forecasted 35-year CPVRR benefit-to-cost ratio of approximately 1.29. The gross CPVRR savings is driven approximately 20.1% by avoided fixed generation and transmission costs, approximately 25% by forecasted realized PTCs from the projects, approximately 48.0% by reduced fuel cost and approximately 6.7% by other reduced variable generation costs.[30]

If only the first five of the fourteen 2025-2027 Solar Projects are pursued, as detailed in DEF witness Borsch's Exhibit BMHB-4-Amended, DEF forecasts a CPVRR net benefit of approximately $313 million, which consists of gross CPVRR savings of approximately $1.029 billion less gross CPVRR costs of approximately $716 million. This amounts to a forecasted CPVRR benefit to cost ratio of approximately 1.44. The gross CPVRR savings is driven approximately 28.0% by avoided fixed generation and transmission costs, approximately 21.9% by forecasted realized PTCs from the projects, approximately 44.3% by reduced fuel costs and approximately 5.8% by reductions in other variable generation costs.[31]

[30] Borsch Exhibit BMHB-3-Amended.
[31] Borsch's Exhibit BMHB-3-Amended.

Q. DID DEF IN ITS COST-EFFECTIVENESS ANALYSIS REVIEW OTHER COMBINATIONS OF SOLAR PROJECTS FOR 2025-2027 BESIDES PURSUIT OF ALL 14 PROJECTS OR JUST THE FIRST FIVE?

A. No. However, it is possible to estimate the incremental economic benefit of the last nine projects from the difference between the DEF results for pursuing all 14 of the projects versus the DEF results for just pursuing the first five projects.

Q. HAVE YOU DONE SO?

A. Yes, I have done so in Exhibit JRD-11. As can be seen from Exhibit JRD-11, the last nine projects incrementally only have a forecasted CPVRR net benefit of approximately $240 million, which consists of gross CPVRR savings of approximately $1.449 billion less gross CPVRR costs of approximately $1.209 billion. This amounts to a forecasted benefit to cost ratio of approximately 1.20, significantly less than the 1.44 for the first five of the 14 projects. The gross CPVRR savings are driven approximately 14.6% by avoided fixed generation and transmission costs, approximately 27.3% by forecasted realized PTCs from the projects, approximately 50.6% by reduced fuel costs and by approximately 7.4% by reductions in other variable generation costs. What is noteworthy is that the contribution from avoided fixed generation and transmission costs is only 14.6% for the last nine projects versus 28.0% for the first five projects. This may be driven by a lower summer firm capacity percentage for the latest of the 2025-2027 Solar Projects versus the earliest of the 2025-2027 Solar Projects.

Q. DOES THIS DECLINING BENEFIT-TO-COST RATIO PERFORMANCE GIVE YOU A CONCERN?

A. Yes. These results suggest the last two to three of the 2025-2027 Solar Projects may not have a robust economic case for them. For example, in the table below, I apply the average results for the first five projects and last nine projects linearly to provide a rough ballpark estimate of how the benefit-to-cost ratio for the individual projects may decline for new projects as they are added.

TABLE JRD-4

Rough Ballpark Estimate of Potential
B to C Ratio Decline 2025-2027 Solar Projects

Project #	Potential B to C Ratio
1	1.51
2	1.47
3	1.44
4	1.41
5	1.37
6	1.34
7	1.30
8	1.27
9	1.23
10	1.20
11	1.17
12	1.13
13	1.10
14	1.06

While the actual behavior may not be linear as shown above, the above table is illustrative with respect to showing that the last couple of 2025-2027 solar projects may not have robust economics particularly since they may have the lowest summer firm capacity percentage.

Q. HOW CAN THIS ISSUE BE RESOLVED?

A. It can be resolved by performing a cost-effectiveness analysis for the last two of the fourteen 2025-2027 Solar Projects with the previous twelve already added. OPC has in discovery requested DEF to perform that analysis.

Q. DID DEF PERFORM A CPVRR BREAKEVEN CALCULATION FOR THE 2025-2027 SOLAR PROJECTS?

A. No. However, from the spreadsheets for DEF's cost-effectiveness analysis provided in response to LULAC/FR POD No. 2, I was able to perform the calculations for pursuit of all 14 of the projects. This is presented in my Exhibit JRD-12. I found that DEF's cost-effectiveness analysis forecasts a CPVRR breakeven for pursuit of all 14 of the 2025-2027 Solar Project by the tenth year of 35-year study period. This is less than halfway through the assumed 30-year design life of the projects and within ten years of the last of the projects entering service.

Q. HAVE THERE BEEN CHANGES TO THE PROJECTS SINCE THEY WERE STUDIED IN 2023 THAT WOULD MATERIALLY AFFECT THE RESULTS OF DEF'S COST EFFECTIVENESS ANALYSIS?

A. Yes. The estimated total projected cost of the 2025-2027 Solar Projects has increased from approximately \$1.604 billion to approximately \$1.663 billion.[32]

[32] Confidential DEF Response to OPC ROG No. 186 at 20240025-OPCROG7-00018141.

Q. CAN THE IMPACT OF THE ABOVE ON DEF'S COST EFFECTIVENESS ANALYSIS BE ROUGHLY ESTIMATED?

A. Yes. I have done so in Exhibit JRD-9 for the pursuit of all 14 projects by scaling the annual revenue requirement for the generation and transmission capital expenditures for the projects by the ratio of 1.663 to 1.604 (1.037:1). The results of Exhibit JRD-13 forecast, under DEF's cost estimate for the projects at the time of the filing of this testimony, a CPVRR net benefit of $487 million consisting of gross CPVRR savings of $2.477 billion less gross CPVRR costs of $1,991 billion. This provides a forecasted benefit to cost ratio of 1.24 for the projects over the 35-year study period. The results also show a forecasted CPVRR breakeven in the 11th year of the 35-year study period, which is within 10 years of the last of the projects entering service.

Q. DID DEF PERFORM ANY FUEL COST SENSITIVITIES IN ITS COST EFFECTIVENESS ANALYSIS FOR THE 2025-2027 SOLAR PROJECTS?

A. It did not. It indicates it did not because, based on its examination its of its 2023 TYSP base, high and low fuel scenarios, it would not produce materially different results.[33]

Q. DO YOU AGREE?

A. Yes. I performed a very rough estimate of the potential impact of using DEF's low fuel forecast scenario and found it only slightly affected the forecasted benefit to

[33] DEF Response to OPC ROG No. 74.

cost ratio of 2025-2027 Solar Projects, by dropping it from 1.24 to 1.23. I performed the very rough estimate by scaling total annual coal and natural gas costs from DEF's EnCompass® production cost runs for the cost effectiveness analysis by the ratio the low case to base case 2023 TYSP coal and natural gas prices. This rough estimate, which included the now higher estimated capital cost of the projects, is provided in Exhibit JRD-14.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE 2025-2027 SOLAR PROJECTS?

A. At the time of the filing of this direct testimony, I am concerned there is not a robust economic case for the last two of the fourteen 2025-2027 Solar Projects, and this weakness is dragging the overall economics of the fourteen 2025-2027 Solar Projects down near below robust economic territory especially when updated capital cost estimates are applied. Given this, I cannot at this time conclude DEF's decision to pursue the last two of the fourteen 2025-2027 Solar Projects was prudent and reasonable. I reserve the right to file supplemental testimony if DEF completes the additional cost effectiveness analysis, including CPVRR benefit to cost ratio and break even calculations, that OPC has requested once I have reviewed those results with respect to the question of whether DEF's decision to pursue the last two projects was not imprudent or unreasonable.

With respect to the first twelve of the fourteen 2025-2027 Solar Projects, while they are elective rather than mandatory, they are consistent with providing reliable electric service at lowest reasonable cost because their economic justification is based on serving DEF's customers and the projected net economic benefit from them is robust. Therefore, based on my analysis, and what I am aware of at the time of filing this testimony, I cannot say that DEF's decision to pursue the first twelve of the fourteen 2025-2027 Solar Projects was imprudent or unreasonable.

V. FORECASTED ECONOMIC PERFORMANCE OF POWERLINE BATTERY PROJECT

Q. LIKE WITH THE CCE PROJECTS AND THE 2025-2027 SOLAR PROJECTS, YOU HAVE CONCLUDED THE POWERLINE BATTERY PROJECT WITH ITS PROJECTED IN-SERVICE DATE IS NOT NECESSARY FOR RELIABILITY AT THIS TIME AND THEREFORE MUST BE SHOWN TO BE FOR THE PURPOSE OF SERVING DEF'S CUSTOMERS, RATHER THAN OFF-SYSTEM SALES, AND HAVE A ROBUST ECONOMIC CASE. HAS DEF PERFORMED ON ECONOMIC ANALYSIS OF THE POWERLINE BATTERY PROJECT?

A. Yes. As with the CCE Projects and the 2025-2027 Solar Projects, DEF performed a cost-effectiveness analysis of the proposed Powerline Battery Project. The results of this analysis are presented in DEF witness Borsch's Exhibit BMHB-6-Amended. The analysis was performed with and without an extra 10% ITC for the project being located in an Energy Community as defined under the IRA.

Q. WAS THE COST-EFFECTIVENESS ANALYSIS THAT DEF PERFORMED FOR THE POWERLINE BATTERY PROJECT PERFORMED IN THE SAME MANNER AS THAT FOR THE 2025-2027 SOLAR PROJECTS?

A. In general it was, but there are a few differences. First, the Powerline Battery Project only has an assumed design life of 15 years such that the total study period is only 19 years. Second, ITCs under the IRA are modeled rather than PTCs since batteries are not eligible for PTCs. Third, the alternative DEF analyzed was a 50 MW four-hour battery added in 2030 and another 50 MW four-hour battery added in 2031.[34] Finally, DEF in Exhibit BMHB-6-Amended lumped the capital cost of the Powerline Battery Project into the change of other generation and transmission capital costs. While the Powerline Battery Project cost is still separately derivable from Exhibit BMHB-6-Amended, it is inconsistent with DEF's presentation in Exhibit BMHB-3-Amended, Exhibit BMHB-4-Amended and Exhibit BMHB-5.

Q. WHAT DOES DEF'S POWERLINE BATTERY PROJECT COST-EFFECTIVENESS ANALYSIS INDICATE?

A. As detailed in DEF witness Borsch's Exhibit BMHB-6-Amended, it indicates that without the extra 10% ITC, the Powerline Battery Project would have a forecasted CPVRR net cost of $5.04 million rather than a forecast CPVRR benefit. With the additional 10% ITC, Exhibit BMHB-6-Amended forecasts a CPVRR net benefit of approximately $3.88 million, which consists of gross CPVRR saving of approximately $143.93 million less gross CPVRR costs of $140.06 million. This amounts to a

[34] DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case Battery Study CPVRR Results.xlsx'.

CPVRR benefit to cost ratio of only 1.03. Note there is no forecasted fuel cost savings. The gross CPVRR savings is being driven approximately 95.6% by avoided fixed generation at transmission costs and 4.3% by variable generation costs unrelated to fuel.

Q. DID DEF PERFORM A CPVRR BREAKEVEN CALCULATION FOR THE POWERLINE BATTERY PROJECT?

A. No. However, from the spreadsheets for DEF's cost-effectiveness analysis provided in response to LULAC/FR POD No. 2, I was able to perform the calculations for Powerline Battery Project. This is presented in my Exhibit JRD-15. I found that even with the additional 10% ITC, DEF's cost effectiveness analysis does not forecast a CPVRR breakeven for the Powerline Battery Project until the 18^{th} year of the 19 year study period – the second to last year of the assumed design life of the battery and well after ten years from when the battery would enter service.

Q. GIVEN THESE RESULTS, WHAT DO YOU CONCLUDE WITH RESPECT TO THE POWERLINE BATTERY PROJECT?

A. The Powerline Battery Project is not needed for reliability at this time and it does not have a robust forecasted CPVRR net benefit. Also, even the forecasted 1.03 CPVRR benefit to cost ratio with the additional 10% ITC is likely overstated as DEF has problematically assumed the same firm capacity percentage from nameplate for two-hour battery as it has for four-hour batteries. Given all this, pursuit of the Powerline Battery Project at this time is not prudent or reasonable because its pursuit at this time is not consistent with providing reliable electric service at lowest reasonable cost. Its costs should be entirely removed from DEF's projected test years in this proceeding.

Q. DEF WITNESS BORSCH IN HIS DIRECT TESTIMONY SUGGESTS THE ECONOMIC SHORTFALL FOR THE POWERLINE BATTERY PROJECT MIGHT BE OVERCOME BY THE PROJECT ALLOWING THE AVOIDANCE OF SOLAR GENERATION OUTPUT CURTAILMENT FOR SOME HOURS NOT WELL-REPRESENTED IN THE ENCOMPASS® MODELING. HE INDICATES THIS AVOIDED SOLAR GENERATION OUTPUT CURTAILMENT MIGHT AMOUNT TO AS MUCH AS 30 HOURS PER YEAR AT THE RATED CAPABILITY OF THE BATTERY OVER THE LIFE OF THE BATTERY.[35] HOW DO YOU RESPOND?

A. It is a highly speculative argument and should be rejected by the Commission. The EnCompass® model already captures the dollar benefit of avoided solar generation output curtailments at the hourly level of granularity. While it is possible for there to be some solar generation output curtailment avoidance that is not captured by the EnCompass® model particularly at the sub-hourly level, there is no evidence it would amount to anything near 30 hours per year at the rated capability of the battery over the life of the battery.

[35] Borsch Direct at 23-24.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Qualifications of James R. Dauphinais

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation, I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[1] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system analysis, power system transients and power system protection

[1] In 2015, Northeast Utilities changed its name to Eversource Energy.

through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000; Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and Midcontinent Independent System Operator, Inc. and Ameren Services Company Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta Utilities Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Idaho Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the Nevada Public Utilities

Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Wisconsin Public Service Commission, the Wyoming Public Service Commission, Federal District Court and various committees of the Illinois, Missouri and South Carolina state legislatures. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource adequacy, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several committees and working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group; Economic Planning Users Group; Loss of Load Expectation Working Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and Reliability Subcommittee. I am currently a member of the MISO Advisory Committee in the end-use customer sector on behalf of industrial customer groups in Illinois, Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2023 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2023	8,270	3,574	43%	0	0	0	0	3,574	43%	0	0	0	0	0
2024	8,899	2,473	28%	0	0	0	0	2,473	28%	0	0	0	0	0
2025	8,728	3,139	36%	187	37	0	0	2,915	33%	0	0	0	0	0
2026	8,814	2,883	33%	296	112	0	0	2,475	28%	0	-171	0	0	0
2027	8,868	2,024	23%	348	187	90	0	1,399	16%	375	-480	0	0	0
2028	8,932	2,000	22%	348	239	90	0	1,323	15%	464	-524	0	0	0
2029	9,019	1,946	22%	348	239	90	37	1,231	14%	573	-524	220	0	0
2030	9,128	1,879	21%	348	239	90	84	1,117	12%	708	-524	664	316	77
2031	9,205	1,852	20%	348	239	90	140	1,034	11%	807	-524	807	459	219
2032	9,366	1,886	20%	348	239	90	206	1,002	11%	871	-524	871	523	284

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2023 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF WINTER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2022/23	8,204	4,155	51%	0	0	0	0	4,155	51%	0	0	0	0	0
2023/24	9,163	3,081	34%	0	0	0	0	3,081	34%	0	0	0	0	0
2024/25	8,954	3,074	34%	100	0	0	0	2,974	33%	0	0	0	0	0
2025/26	8,979	2,828	31%	187	0	0	0	2,641	29%	0	-226	0	0	0
2026/27	9,004	2,980	33%	296	0	0	0	2,684	30%	0	-226	0	0	0
2027/28	8,427	2,465	29%	348	0	90	0	2,027	24%	0	-669	0	0	0
2028/29	8,494	2,398	28%	348	0	90	0	1,960	23%	0	-669	0	0	0
2029/30	8,583	2,376	28%	348	0	90	0	1,938	23%	0	-669	0	0	0
2030/31	8,639	2,388	28%	348	0	90	67	1,883	22%	0	-669	0	0	0
2031/32	8,766	2,327	27%	348	0	90	135	1,754	20%	0	-669	0	0	0

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.

b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.

c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.2 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2024 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2024	9,000	2,369	26%	0	0	0	0	2,369	26%	0	0	0	0	0
2025	8,836	2,603	29%	206	19	0	0	2,379	27%	0	0	0	0	0
2026	8,790	3,184	36%	389	75	0	0	2,720	31%	0	0	0	0	0
2027	8,781	2,257	26%	389	169	90	0	1,609	18%	147	-460	0	0	0
2028	8,908	2,247	25%	389	262	90	0	1,506	17%	276	-460	0	0	0
2029	9,093	2,149	24%	389	262	90	85	1,323	15%	496	-460	36	0	0
2030	9,260	2,076	22%	389	262	90	177	1,158	12%	695	-460	695	306	43
2031	9,374	2,016	22%	389	262	90	277	998	11%	877	-460	877	488	226
2032	9,595	2,279	24%	389	262	90	337	1,200	13%	719	-460	719	330	67
2033	9,811	2,545	26%	389	262	90	397	1,407	14%	556	-460	556	167	0

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2024 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF WINTER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2023/24	8,872	3,323	37%	0	0	0	0	3,323	37%	0	0	0	0	0
2024/25	9,112	2,465	27%	99	0	0	0	2,366	26%	0	0	0	0	0
2025/26	9,124	2,847	31%	216	0	0	0	2,631	29%	0	0	0	0	0
2026/27	9,165	2,739	30%	347	0	0	0	2,392	26%	0	-198	0	0	0
2027/28	8,682	2,220	26%	347	0	90	0	1,783	21%	0	-591	0	0	0
2028/29	8,795	2,179	25%	347	0	90	72	1,670	19%	89	-591	0	0	0
2029/30	8,957	2,089	23%	347	0	90	144	1,508	17%	284	-591	0	0	0
2030/31	9,017	2,100	23%	347	0	90	216	1,447	16%	356	-591	356	9	9
2031/32	9,125	1,993	22%	347	0	90	216	1,340	15%	485	-591	485	138	138
2032/33	9,210	2,377	26%	347	0	90	682	1,258	14%	584	-591	584	237	237

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.2 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2023 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2023	8,270	3,574	43%	0	0	0	0	3,574	43%	0	0	0	0	0
2024	8,899	2,473	28%	0	0	0	0	2,473	28%	0	0	0	0	0
2025	8,728	3,139	36%	187	37	0	0	2,915	33%	0	0	0	0	0
2026	8,814	2,883	33%	296	112	0	0	2,475	28%	0	0	0	0	0
2027	8,868	2,024	23%	348	187	90	0	1,399	16%	375	-309	66	0	0
2028	8,932	2,000	22%	348	239	90	0	1,323	15%	464	-353	111	0	0
2029	9,019	1,946	22%	348	239	90	37	1,231	14%	573	-353	220	0	0
2030	9,128	1,879	21%	348	239	90	84	1,117	12%	708	-353	664	316	77
2031	9,205	1,852	20%	348	239	90	140	1,034	11%	807	-353	807	459	219
2032	9,366	1,886	20%	348	239	90	206	1,002	11%	871	-353	871	523	284

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2023 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF WINTER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2022/23	8,204	4,155	51%	0	0	0	0	4,155	51%	0	0	0	0	0
2023/24	9,163	3,081	34%	0	0	0	0	3,081	34%	0	0	0	0	0
2024/25	8,954	3,074	34%	100	0	0	0	2,974	33%	0	0	0	0	0
2025/26	8,979	2,828	31%	187	0	0	0	2,641	29%	0	0	0	0	0
2026/27	9,004	2,980	33%	296	0	0	0	2,684	30%	0	0	0	0	0
2027/28	8,427	2,465	29%	348	0	90	0	2,027	24%	0	-443	0	0	0
2028/29	8,494	2,398	28%	348	0	90	0	1,960	23%	0	-443	0	0	0
2029/30	8,583	2,376	28%	348	0	90	0	1,938	23%	0	-443	0	0	0
2030/31	8,639	2,388	28%	348	0	90	67	1,883	22%	0	-443	0	0	0
2031/32	8,766	2,327	27%	348	0	90	135	1,754	20%	0	-443	0	0	0

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.2 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2024 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2024	9,000	2,369	26%	0	0	0	0	2,369	26%	0	0	0	0	0
2025	8,836	2,603	29%	206	19	0	0	2,379	27%	0	0	0	0	0
2026	8,790	3,184	36%	389	75	0	0	2,720	31%	0	0	0	0	0
2027	8,781	2,257	26%	389	169	90	0	1,609	18%	147	-309	0	0	0
2028	8,908	2,247	25%	389	262	90	0	1,506	17%	276	-309	0	0	0
2029	9,093	2,149	24%	389	262	90	85	1,323	15%	496	-309	187	0	0
2030	9,260	2,076	22%	389	262	90	177	1,158	12%	695	-309	695	306	43
2031	9,374	2,016	22%	389	262	90	277	998	11%	877	-309	877	488	226
2032	9,595	2,279	24%	389	262	90	337	1,200	13%	719	-309	719	330	67
2033	9,811	2,545	26%	389	262	90	397	1,407	14%	556	-309	556	167	0

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
2024 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF WINTER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS		PROPOSED[a] CCE PROJECTS	PROPOSED[b] 2025-2027 SOLAR	PROPOSED[c] POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS		20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2023/24	8,872	3,323	37%	0	0	0	0	3,323	37%	0	0	0	0	0
2024/25	9,112	2,465	27%	99	0	0	0	2,366	26%	0	0	0	0	0
2025/26	9,124	2,847	31%	216	0	0	0	2,631	29%	0	0	0	0	0
2026/27	9,165	2,739	30%	347	0	0	0	2,392	26%	0	0	0	0	0
2027/28	8,682	2,220	26%	347	0	90	0	1,783	21%	0	-393	0	0	0
2028/29	8,795	2,179	25%	347	0	90	72	1,670	19%	89	-393	0	0	0
2029/30	8,957	2,089	23%	347	0	90	144	1,508	17%	284	-393	0	0	0
2030/31	9,017	2,100	23%	347	0	90	216	1,447	16%	356	-393	356	9	9
2031/32	9,125	1,993	22%	347	0	90	216	1,340	15%	485	-393	485	138	138
2032/33	9,210	2,377	26%	347	0	90	682	1,258	14%	584	-393	584	237	237

Notes:

a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.

b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.

c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.2 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
CCE Projects
Breakeven
($2022 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2022	1	$0.000	$0.000	$0.000	N/A
$\boxed{2023}$	2	$0.575	$0.548	$\boxed{\$0.027}$	1.05
2024	3	$3.214	$1.406	$1.808	2.29
2025	4	$13.998	$6.942	$7.056	2.02
2026	5	$30.071	$15.926	$14.144	1.89
2027	6	$48.907	$25.807	$23.101	1.90
2028	7	$67.034	$36.216	$30.818	1.85
2029	8	$91.507	$46.602	$44.904	1.96
2030	9	$118.901	$56.001	$62.900	2.12
2031	10	$143.702	$64.501	$79.201	2.23
2032	11	$167.548	$72.183	$95.365	2.32
2033	12	$202.736	$79.120	$123.616	2.56
2034	13	$252.083	$85.377	$166.706	2.95
2035	14	$296.133	$90.789	$205.344	3.26
2036	15	$337.120	$95.510	$241.610	3.53
2037	16	$369.893	$99.756	$270.137	3.71
2038	17	$409.715	$103.566	$306.149	3.96
2039	18	$437.777	$106.978	$330.799	4.09
2040	19	$469.853	$110.026	$359.827	4.27
2041	20	$505.571	$112.743	$392.827	$\boxed{4.48}$

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case - CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and '2024 Rate Case CC HR Upgrade Study CPVRR Results'.

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
CCE Projects
Breakeven
OPC Estimate
Updated Capital Costs + Hypothetical Retirement of All CC Units at End of 2041
($2022 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2022	1	$0.000	$0.000	$0.000	N/A
2023	2	$0.575	$0.680	($0.105)	0.85
2024	3	$3.214	$1.744	$1.470	1.84
2025	4	$13.998	$8.609	$5.388	1.63
2026	5	$30.071	$19.752	$10.319	1.52
2027	6	$48.907	$32.005	$16.902	1.53
2028	7	$67.034	$44.915	$22.119	1.49
2029	8	$91.507	$57.796	$33.711	1.58
2030	9	$118.901	$69.452	$49.449	1.71
2031	10	$143.702	$79.993	$63.708	1.80
2032	11	$167.548	$89.521	$78.027	1.87
2033	12	$202.736	$98.124	$104.612	2.07
2034	13	$252.083	$105.884	$146.200	2.38
2035	14	$296.133	$112.596	$183.537	2.63
2036	15	$337.120	$118.451	$218.669	2.85
2037	16	$369.893	$123.716	$246.176	2.99
2038	17	$409.715	$128.441	$281.274	3.19
2039	18	$437.777	$132.673	$305.104	3.30
2040	19	$469.853	$136.454	$333.400	3.44
2041	20	$505.571	$154.430	$351.141	3.27

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case - CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and '2024 Rate Case CC HR Upgrade Study CPVRR Results'.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects
OPC Estimate for Last Nine Projects
CPVRR
($2023 Millions)

	First 5 Projects (1)	All 14 Projects (2)	Estimate Last 9 Projects (3)
Fuel Cost	456	1,189	733
Environmental Costs	1	1	0
Variable Costs	59	166	107
PTC	(1)	0	1
Inc Transmission and FOM Cost	61	110	49
Inc Gen Capital	227	390	163
	803	1,856	1,053
Transm and FOM Add Solar	(97)	(265)	(168)
Gen Capital Add Solar	(619)	(1,660)	(1,041)
	(716)	(1,925)	(1,209)
PTC Add Solar	225	621	396
Add Solar Savings	312	552	240
B to C Ratio	1.44	1.29	1.20

Source: DEF Exhibits BMHB-3-Amended and BHMB-4-Amended

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)
Breakeven
($2023 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2023	1	$ (0)	$ 2	$ (2)	N/A
2024	2	$ (0)	$ 16	$ (16)	0.00
2025	3	$ 21	$ 80	$ (59)	0.26
2026	4	$ 110	$ 206	$ (97)	0.53
2027	5	$ 235	$ 362	$ (127)	0.65
2028	6	$ 397	$ 514	$ (117)	0.77
2029	7	$ 538	$ 649	$ (111)	0.83
2030	8	$ 678	$ 770	$ (92)	0.88
2031	9	$ 812	$ 880	$ (68)	0.92
2032	10	$ 980	$ 980	$ 0	1.00
2033	11	$1,136	$ 1,071	$ 65	1.06
2034	12	$1,274	$ 1,154	$ 120	1.10
2035	13	$1,400	$ 1,230	$ 170	1.14
2036	14	$1,497	$ 1,300	$ 197	1.15
2037	15	$1,576	$ 1,363	$ 213	1.16
2038	16	$1,640	$ 1,425	$ 215	1.15
2039	17	$1,703	$ 1,482	$ 222	1.15
2040	18	$1,762	$ 1,533	$ 229	1.15
2041	19	$1,818	$ 1,579	$ 238	1.15
2042	20	$1,867	$ 1,622	$ 246	1.15
2043	21	$1,925	$ 1,660	$ 265	1.16
2044	22	$1,980	$ 1,695	$ 285	1.17
2045	23	$2,024	$ 1,726	$ 298	1.17
2046	24	$2,065	$ 1,755	$ 310	1.18
2047	25	$2,098	$ 1,780	$ 318	1.18
2048	26	$2,122	$ 1,804	$ 318	1.18
2049	27	$2,160	$ 1,825	$ 334	1.18
2050	28	$2,232	$ 1,845	$ 388	1.21
2051	29	$2,281	$ 1,862	$ 419	1.22
2052	30	$2,337	$ 1,878	$ 459	1.24
2053	31	$2,383	$ 1,893	$ 490	1.26
2054	32	$2,425	$ 1,906	$ 519	1.27
2055	33	$2,457	$ 1,918	$ 539	1.28
2056	34	$2,476	$ 1,923	$ 553	1.29
2057	35	$2,477	$ 1,925	$ 552	1.29

Sources: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)
Breakeven
OPC Estimate
Updated Capital Costs
($2023 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2023	1	$ (0)	$ 2	$ (2)	N/A
2024	2	$ (0)	$ 16	$ (16)	0.00
2025	3	$ 21	$ 83	$ (62)	0.25
2026	4	$ 110	$ 214	$ (104)	0.51
2027	5	$ 235	$ 375	$ (140)	0.63
2028	6	$ 397	$ 532	$ (135)	0.75
2029	7	$ 538	$ 672	$ (134)	0.80
2030	8	$ 678	$ 797	$ (119)	0.85
2031	9	$ 812	$ 911	$ (99)	0.89
2032	10	$ 980	$ 1,014	$ (34)	0.97
2033	11	$ 1,136	$ 1,108	$ 27	1.02
2034	12	$ 1,274	$ 1,194	$ 80	1.07
2035	13	$ 1,400	$ 1,273	$ 127	1.10
2036	14	$ 1,497	$ 1,345	$ 152	1.11
2037	15	$ 1,576	$ 1,411	$ 166	1.12
2038	16	$ 1,640	$ 1,475	$ 166	1.11
2039	17	$ 1,703	$ 1,533	$ 170	1.11
2040	18	$ 1,762	$ 1,586	$ 176	1.11
2041	19	$ 1,818	$ 1,634	$ 184	1.11
2042	20	$ 1,867	$ 1,678	$ 190	1.11
2043	21	$ 1,925	$ 1,717	$ 208	1.12
2044	22	$ 1,980	$ 1,753	$ 227	1.13
2045	23	$ 2,024	$ 1,785	$ 238	1.13
2046	24	$ 2,065	$ 1,815	$ 250	1.14
2047	25	$ 2,098	$ 1,842	$ 256	1.14
2048	26	$ 2,122	$ 1,866	$ 256	1.14
2049	27	$ 2,160	$ 1,888	$ 272	1.14
2050	28	$ 2,232	$ 1,908	$ 324	1.17
2051	29	$ 2,281	$ 1,926	$ 355	1.18
2052	30	$ 2,337	$ 1,943	$ 395	1.20
2053	31	$ 2,383	$ 1,958	$ 426	1.22
2054	32	$ 2,425	$ 1,971	$ 454	1.23
2055	33	$ 2,457	$ 1,983	$ 474	1.24
2056	34	$ 2,476	$ 1,989	$ 487	1.25
2057	35	$ 2,477	$ 1,991	$ 487	1.24

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)
Breakeven
OPC Estimate
Updated Capital Costs + 2023 TYSP Low Case Fuel Prices
($2023 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2023	1	$ (0)	$ 2	$ (2)	N/A
2024	2	$ (0)	$ 16	$ (16)	0.00
2025	3	$ 20	$ 83	$ (62)	0.25
2026	4	$ 104	$ 214	$ (109)	0.49
2027	5	$ 220	$ 375	$ (155)	0.59
2028	6	$ 376	$ 532	$ (156)	0.71
2029	7	$ 512	$ 672	$ (160)	0.76
2030	8	$ 653	$ 797	$ (145)	0.82
2031	9	$ 788	$ 911	$ (123)	0.87
2032	10	$ 959	$ 1,014	$ (55)	0.95
2033	11	$ 1,117	$ 1,108	$ 9	1.01
2034	12	$ 1,259	$ 1,194	$ 65	1.05
2035	13	$ 1,388	$ 1,273	$ 115	1.09
2036	14	$ 1,488	$ 1,345	$ 143	1.11
2037	15	$ 1,570	$ 1,411	$ 159	1.11
2038	16	$ 1,635	$ 1,475	$ 160	1.11
2039	17	$ 1,699	$ 1,533	$ 166	1.11
2040	18	$ 1,757	$ 1,586	$ 171	1.11
2041	19	$ 1,811	$ 1,634	$ 177	1.11
2042	20	$ 1,858	$ 1,678	$ 180	1.11
2043	21	$ 1,913	$ 1,717	$ 195	1.11
2044	22	$ 1,964	$ 1,753	$ 211	1.12
2045	23	$ 2,003	$ 1,785	$ 218	1.12
2046	24	$ 2,040	$ 1,815	$ 225	1.12
2047	25	$ 2,068	$ 1,842	$ 226	1.12
2048	26	$ 2,088	$ 1,866	$ 222	1.12
2049	27	$ 2,121	$ 1,888	$ 233	1.12
2050	28	$ 2,194	$ 1,908	$ 286	1.15
2051	29	$ 2,242	$ 1,926	$ 316	1.16
2052	30	$ 2,299	$ 1,943	$ 356	1.18
2053	31	$ 2,345	$ 1,958	$ 387	1.20
2054	32	$ 2,387	$ 1,971	$ 415	1.21
2055	33	$ 2,418	$ 1,983	$ 435	1.22
2056	34	$ 2,437	$ 1,989	$ 449	1.23
2057	35	$ 2,439	$ 1,991	$ 448	1.23

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.
DEF Response to OPC POD No. 34 at 2024-0025-OPCPOD4-00018097 through 00018098.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
Powerline Battery Project (40% ITC with no Haircut)
Breakeven
($2023 Millions)

Year (1)	Study Year (2)	CPVRR Gross Benefit (3)	CPVRR Gross Cost (4)	CPVRR Net Benefit (5)	CPVRR Benefit to Cost Ratio (6)
2023	1	$ 0.46	$ 0.11	$ 0.35	N/A
2024	2	$ 0.46	$ 0.11	$ 0.35	N/A
2025	3	$ 0.46	$ 0.11	$ 0.35	N/A
2026	4	$ 0.32	$ (0.17)	$ 0.49	N/A
2027	5	$ 1.68	$ 17.34	$ (15.65)	0.10
2028	6	$ 3.00	$ 32.02	$ (29.02)	0.09
2029	7	$ 4.78	$ 44.68	$ (39.91)	0.11
2030	8	$ 16.76	$ 57.01	$ (40.26)	0.29
2031	9	$ 35.63	$ 68.29	$ (32.67)	0.52
2032	10	$ 52.50	$ 78.91	$ (26.41)	0.67
2033	11	$ 67.68	$ 88.93	$ (21.25)	0.76
2034	12	$ 81.31	$ 97.86	$ (16.55)	0.83
2035	13	$ 93.41	$ 105.99	$ (12.58)	0.88
2036	14	$ 103.78	$ 113.26	$ (9.48)	0.92
2037	15	$ 113.36	$ 119.76	$ (6.41)	0.95
2038	16	$ 122.54	$ 125.60	$ (3.06)	0.98
2039	17	$ 130.25	$ 131.27	$ (1.02)	0.99
2040	18	$ 137.24	$ 135.83	$ 1.41	1.01
2041	19	$ 143.98	$ 140.10	$ 3.89	1.03

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Battery Study_40pctITC_Results.xlsx' and '2024 Rate Case Battery Study CPVRR Results.xlsx'.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC.	Docket No. 20240025-EI Dated: May 3, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO FLORIDA RISING'S & LEAGUE OF UNITED LATIN AMERICAN CITIZENS' FIRST SET OF INTERROGATORIES (NOS. 1-22)

Duke Energy Florida, LLC ("DEF") responds to the League of United Latin American Citizens of Florida ("LULAC") and Florida Rising's First Set of Interrogatories to DEF (Nos. 1-22), as follows:

9. Please provide DEF's current loss of load probability, as well as any projected loss of load probabilities for 2025, 2026, 2027, and 2028.

Response:

DEF has not prepared a utility or BA specific LOLP study in the last several years. Because of the high level of integration of the DEF system into the FRCC system as a whole, the extensive use of reserve sharing and the existence of a single reliability coordinator for the state, it is more relevant to review data that incorporates the behavior of the entire interlinked system. In addition, over many years, DEF has established that maintaining the 20% utility reserve margin agreed to in previous PSC orders provides DEF with adequate resources to assure an LOLP below the 1 day in ten years target that is the industry standard.

FRCC performs a state-wide LOLP analysis every other year in even numbered years. DEF, along with all FRCC members, contributes data to that analysis and participates in review of the results. The following discussion is excerpted from the 2022 FRCC Reliability Analysis describing the results of the 2022 LOLP study.
For the 2022 LOLP analysis, the RS collected projected hourly solar output and energy storage charging and discharging profiles for all utility-scale units and treated them as a modifier to the load in order to further improve the assessment model. The purpose is to verify that the projected LOLP for the system does not exceed the maximum target LOLP of 0.1 day in a given year. In addition to maintaining this LOLP level, the FRCC established an additional Regional Reserve Margin Planning Criterion (also known as a Resource Adequacy Criteria) of a minimum 15% Total Reserve Margin for both summer and winter versus firm load.

The most recent LOLP analysis was conducted in 2022. “Base” LOLP projections were obtained for the FRCC Region for the years 2022 through 2026 using updated assumptions and forecasts that correspond with the Florida utilities’ 2022 TYSPs. Beyond the base or “reference” case values for LOLP, projected LOLP values for a variety of scenarios were considered, including: (i) no availability of firm imports, (ii) no availability of load management/demand response (DR) types of DSM programs, and (iii) a high load case.

Results indicate that the FRCC Region is projected to be reliable from an LOLP perspective through 2026. In other words, the FRCC Region’s electric system is projected not to exceed the planning maximum LOLP criterion of 0.1 days per year with all transmission facilities in service for the reference case and the scenario cases. The projected LOLP values are shown in Table 1.

Table 1
2022 FRCC LOLP Results

Year	Base Case	No Availability of Firm Imports	No Availability of Demand Response	High Case
	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2022	0.000003	0.000957	0.015117	0.000008
2023	0.000003	0.000441	0.015003	0.000008
2024	0.000002	0.000652	0.014572	0.000009
2025	0.000004	0.000688	0.010994	0.000011
2026	0.000002	0.000597	0.008826	0.000009

The 2022 LOLP results are based on: (i) a load variation model and (ii) a manual approach to generator maintenance inputs which typically results in higher LOLP values than would result if using an automatic maintenance approach.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC.	Docket No. 20240025-EI Dated: May 8, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
<u>CITIZENS' FOURTH SET OF INTERROGATORIES (NOS. 71-79)</u>

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fourth Set of Interrogatories to DEF (Nos. 71-79), as follows:

74. Integrated Resource Plan Portfolio Fuel Price Forecast. Please refer to the Direct Testimony of Company Witness Borsch at 10.

a. Please describe in detail whether the Company used any fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast.

b. If the Company used additional fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast, please identify and describe in detail each such additional fuel price forecast.

c. If the Company did not use additional fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast, please explain in detail why the Company did not do so.

<u>Response:</u>

DEF annually creates high and low fuel price scenarios. These price scenarios for the fall of 2022, i.e. contemporary to the forecast used in the 2023 TYSP, are included in DEF's response to Citizens POD 4-34.

a. The company did not make use of the high and low fuel price scenarios in developing the TYSP used in developing testimony in this case.

b. N/A

c. Examination of the high and low fuel price scenarios indicated that they would not provide results that would be materially different from the base case forecast in the evaluation of the projected resource plan.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC.	Docket No. 20240025-EI Dated: May 8, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
CITIZENS' FOURTH SET OF INTERROGATORIES (NOS. 71-79)

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fourth Set of Interrogatories to DEF (Nos. 71-79), as follows:

75. **Solar Equivalent Firm Capacity Contribution.** Please refer to the Direct Testimony of Company Witness Borsch at 11.

a. Please provide a detailed description of how the Company determined its approximately 1,050 MW of proposed solar generation additions for 2025-2027 have an expected equivalent summer firm capacity contribution of approximately 262 MW. This should include identification of any modeling tools used by the Company to make the determination.

b. Please identify the expected equivalent winter firm capacity contribution in MW of the approximately 1,050 MW of solar generation additions the Company has proposed for 2025-2027.

c. Please provide a detailed description of how the Company determined the value provided in response to b. above. This should include identification of any modeling tools used by the Company to make the determination.

Response:

a. DEF regularly validates our assumption with actuals. Attachment OPC ROG 4 -75a 75b, bearing Bates numbers 20240025-OPCROG4-00018673 through 20240025-OPCROG4-00018674, shows that the average contribution for all the existing DEF owned solar units at the time of the summer peak demand is 60%, which is close to the conservative assumption of 57% used in the DEF model.

b. The expected equivalent winter firm capacity contribution in MW of the approximately 1,050 MW of solar generation additions the Company has proposed for 2025-2027 is zero MW. DEF's winter peak is generally reached in January in the hour ending 8 am and the solar contribution at that time is zero.
DEF regularly validates our assumption with actuals. Attachment OPC ROG 4 -75a 75b shows that the average contribution for all the existing DEF owned solar units at the time of the winter peak demand is approximately 3%, which is in line with DEF's conservative assumption of 0%.

c. Please refer to response to LULAC ROG 1 – Q12 and LULAC POD ROG 1-Q01.

Units	Aug 2023	Jun 2022	Aug 2021	Jun 2020	Jun 2019
Bay Ranch Solar	69				
Bay Trail Solar	47	44			
Canoe Creek Solar	1	2	2	2	3
Charlie Creek Solar	51				
Columbia Solar	41	68	44	62	
Debary Solar	16	46	23	51	
Duette Solar	45	43			
Fort Green Solar	8	34			
Hardeetown Solar	42	69	34	54	71
Hamilton Solar	52				
High Springs Solar	32				
Hildreth Solar	59				
Lake Placid Solar	19	27	0	45	
Longleaf/Bell Ridge Solar	16				
Perry Solar	2	2	2	2	2
Sandy Creek Solar	64	45			
Santa Fe Solar	36	52	58		
Suwannee Solar	4	4	1	5	7
Trenton Solar	46	49	42	57	
Twin Rivers Solar	48	65	37		

Capacity	Solar Contribution to the Peak Demand				
MWs	2023	2022	2021	2020	2019
74.9	92%				
74.9	63%	59%			
3.8	26%	53%	53%	53%	79%
74.9	68%				
74.9	55%	91%	59%	83%	
74.5	21%	62%	31%	68%	
74.5	60%	58%			
74.9	11%	45%			
74.9	56%	92%	45%	72%	95%
74.9	69%				
74.9	43%				
74.9	79%				
45	42%	60%	0%	100%	
74.9	21%				
5.1	39%	39%	39%	39%	39%
74.9	85%	60%			
74.9	48%	69%	77%		
8.8	45%	45%	11%	57%	80%
74.9	61%	65%	56%	76%	
74.9	64%	87%	49%		
59.91%	**53%**	**63%**	**42%**	**69%**	**73%**

HE	6PM	5PM	5PM	5PM	5PM

Units	2024	2023	2022	2021	2020	2019
Bay Ranch Solar	21					
Bay Trail Solar	22	2				
Canoe Creek Solar	1	1	0	0	0	0
Charlie Creek Solar	29	5				
Columbia Solar	29	3	4	3		
Debary Solar	17	1	3	2		
Duette Solar	26	3	5			
Fort Green Solar	22	0				
Hardeetown Solar	23					
Hamilton Solar	26	2	2	2	2	3
High Springs Solar	24					
Hildreth Solar	13					
Lake Placid Solar	11	1	2	2	2	
Perry Solar	1	0	0	0	0	0
Sandy Creek Solar	22	1				
Santa Fe Solar	18	0	3			
Suwannee Solar	1	0	0	1	0	0
Trenton Solar	12	2	3			
Twin Rivers Solar	24	1	2	2	1	

Capacity	Solar Contribution to the Peak Demand					
MWs	2024	2023	2022	2021	2020	2019
74.9	28%					
74.9	29%	3%				
3.8	26%	26%	0%	0%	0%	0%
74.9	39%	7%				
74.9	39%	4%	5%	4%		
74.5	23%	1%	4%	3%		
74.5	35%	4%	7%			
74.9	29%	0%				
74.9	31%					
74.9	35%	3%	3%	3%	3%	4%
74.9	32%					
74.9	17%					
45	24%	2%	4%	4%	4%	
5.1	20%	0%	0%	0%	0%	0%
74.9	29%	1%				
74.9	24%	0%	4%			
8.8	11%	0%	0%	11%	0%	0%
74.9	16%	3%	4%			
74.9	32%	1%	3%	3%	1%	
6.67%	**27%**	**4%**	**3%**	**3%**	**1%**	**1%**
2.53%						
HE	9AM	8AM	8AM	8AM	8AM	8AM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC.	Docket No. 20240025-EI Dated: June 7, 2024

DUKE ENERGY FLORIDA, LLC'S AMENDED RESPONSE TO CITIZENS' SIXTH SET OF INTERROGATORIES (NOS. 118-143)

Duke Energy Florida, LLC ("DEF") submits its second supplemental response to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Sixth Set of Interrogatories to DEF (Nos. 118-143), specifically 118, as follows:

INTERROGATORIES

118. **Resource Addition Timing**

Please refer to the Direct Testimony of DEF Witness Benjamin Borsch at p. 9-10 and p. 16 and the Company's April 2024 Ten-Year Site Plan.

a. For each year from 2025 through 2026, inclusive, please identify each resource addition difference, if any, between the resource additions proposed by the Company in this proceeding and the resource additions proposed in the Company's April 2024 10-Year Site Plan.

b. For each difference identified in response to a., please provide a detailed explanation with respect to why there is a difference.

Response:

a. and b.

2025 – 2026 Solar Resources.

	Solar Units	2024 Rate Case ISM	2024 Rate Case ISY	2024 TYSP ISM	2024 TYSP ISY	Differences	
1	Solar 2025	March	2025	March	2025		
2	Solar 2025	March	2025	December	2025	delayed	9 months
3	Solar 2025	December	2025	January	2026	delayed	1 month
4	Solar 2025	December	2025	January	2026	delayed	1 month
5	Solar 2025	December	2025	June	2026	delayed	6 months
6	Solar 2025	December	2025	June	2026	delayed	6 months
7	Solar 2026	June	2026	June	2026		
8	Solar 2026	June	2026	December	2026	delayed	6 months
9	Solar 2026	June	2026	December	2026	delayed	12 months
10	Solar 2026	June	2026	June	2027	delayed	12 months

Explanation for the 2025-2026 solar resources delays:

There has been a significant delay over the last year for High Side Breakers which are necessary to interconnect the solar site to the transmission grid. In May of 2023 lead times started to increase from 30 weeks to 155 weeks in February of 2024 and currently 170 weeks in April. This has made the ability to obtain breakers at the necessary timing extremely difficult. Due to these delays, the intended backfeed dates and in-service dates have slipped.

Combined Cycle Heat Rate Upgrades.

CC Heat Rate Upgrades	2024 Rate Case ISM	2024 Rate Case ISY	2024 TYSP ISM	2024 TYSP ISY	Differences	
Bartow CC	November	2024	November	2024		
Citrus 1	December	2025	May	2026	delayed	5 months
Citrus 2	April	2026	May	2026	delayed	1 month
Hines 2	May	2025	May	2025		
Hines 3	May	2026	April	2026	accelerated	1 month
Hines 4	December	2027	November	2025	accelerated	25 months
Osprey	June	2023	June	2023		
Tiger Bay	May	2025	March	2026	delayed	10 months

Explanation for the change in schedule for the Combined Cycle Heat Rate upgrades:

Parts for these projects are being ordered and purchased, so the schedule is moving according to logistics constraints. DEF is trying to optimize the maintenance outages for its fleet, so the in-service days for the projects move accordingly.

185.

186. **Solar and Battery.** Refer to the testimony of Benjamin Borsch, at page 4, lines 20-22. Provide a list of the 1,050 MW solar projects and the 100 MW battery storage identifying, by each individual project, the planned starting date, planned in-service date and the projected cost. Also identify by each individual project whether permitting has been completed and if not completed, identify the status.

Response:

Please see attachment bearing Bates number 20240025-OPCROG7-00018141, for the requested information requested for the DEF owned solar projects with commercial operation dates from 2025-2027. The documents are confidential: redacted versions are attached hereto and unredacted copies have been submitted with the Florida Public Service Commission along with DEF's Notice of Intent to Request Confidential Classification dated May 7, 2024.

REDACTED

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

2025 Solar	Named Project	Filing In Service Date	Planned In Service Date	Permitting Status	Planned Construction Start	Filed Project Cost	Anticipated Project Cost
2025 - Project #1	Sundance	March 2025	March 2025	Expected May 2024	May 2025	[redacted]	
2025 - Project #2	Rattler	March 2025	December 2025	Expected 3Q 2024	1Q 2025		
2025 - Project #3	Half Moon	December 2025	January 2026	Expected 3Q 2024	1Q 2025		
2025 - Project #4	Bailey Mill	December 2025	January 2026	Expected 3Q 2024	1Q 2025		
2025 - Project #5	-	December 2025	June 2026	Expected 1Q 2025	3Q 2025		
2025 - Project #6	-	December 2025	June 2026	Expected 1Q 2025	3Q 2025		
2026 - Project #1	-	June 2026	June 2026	Expected 1Q 2025	3Q 2025		
2026 - Project #2	-	June 2026	December 2026	Expected 3Q 2025	1Q 2026		
2026 - Project #3	-	June 2026	December 2026	Expected 3Q 2025	1Q 2026		
2026 - Project #4	-	June 2026	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #1	-	June 2027	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #2	-	June 2027	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #3	-	June 2027	December 2027	Expected 3Q 2026	1Q 2027		
2027 - Project #4	-	June 2027	December 2027	Expected 3Q 2026	1Q 2027		

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20240025-EI

_______________________________/

VOLUME II
(Pages 70 through 185)

VIDEO-TELECONFERENCE
DEPOSITION OF BENJAMIN BORSCH
(Taken on behalf of the Office of Public Counsel)

DATE TAKEN: May 30, 2024
TIME: 8:30 a.m. - 6:03 p.m.
PLACE: Zoom

Examination of the witness taken before:

JESSICA RENCHEN, Court Reporter
On Behalf of
For The Record Reporting

D E P O S I T I O N

(Deposition continued from Volume I)

THE COURT REPORTER: This is the Court Reporter; I'm ready to go back on.

MS. WESSLING: Okay, great.

And Mr. Borsch, you're ready?

THE WITNESS: Ready.

CONTINUED EXAMINATION

BY MS. WESSLING:

Q. Okay. So I believe we were looking at Schedule 8 of the revised 10-year site plan and --

A. Yes.

Q. Okay. I believe the question that I was asking was, it looks like there are some proposed combustion turbine generation facility retirements at Bayboro, DeBary and Bartow in 2026 and 2027. Is that accurate?

A. Yes.

Q. Okay. And is this information still accurate?

A. Yes.

Q. Okay. If all three of these are retired, that will result in approximately 460 megawatts of summer capacity being retired, would you agree?

A. Subject to check, yes.

Q. Okay. Could you just explain how and why the decision was made to retire each of those units?

A. Yes. I mean, principally the reason that we're retiring those units is that they're old. And as they continue to age, maintenance gets trickier and the reliability goes down and eventually costs will go up.

In the specific case of Bayboro, where Bayboro is located right next -- like just down the street here from us here in St. Petersburg and right next to the Bay, we have identified that there's a significant environmental risk associated with the oil tanks that are there at Bayboro. Now, mind you, to my knowledge, we have never had a release. However, as the tanks age, as the equipment ages, that environmental risk does rise and that's a sensitive and publicly visible waterway. So that really was one of the key drivers of the decision to retire the Bayboro units in particular.

The other units, those are all, first of all, aging, but second of all, they're all oil fired units with very low utilization rates. They are expensive to operate because they are oil fired. And given that we have been in a period of relatively high reserve margins, there was an opportunity to retire those units eventually. Meaning, closer to 2030 we'll build capacity that will replace them, but it'll be new capacity. As I say, most of those units are over 50 years old already.

Q. All right. And what analysis do you and your group specifically do related to the retirements contained in this 10-year site plan?

A. In this case, we didn't do a specific analysis of those retirements. Because of the fact that they are effectively at the ends of their lives, a specific analysis didn't appear to be required. So we worked with the generation group and it's really, this is information that we're getting from Mr. Anderson's department that from a maintenance perspective and an age perspective that those units are ready for retirement.

Q. So there is no analysis done about the prudence or reasonableness of those proposed retirements?

A. There is not a specific cost-effectiveness or cost analysis of those retirements.

Q. Okay. Did you listen to Mr. Anderson's deposition last Friday?

A. I did not.

Q. Okay. Well, he mentioned something called a

Q. Are you going to be making any amendments to your testimony or BMHB-2 based off of the information reflected in Staff's Interrogatory Number 2?

MS. TRIPLETT: Object to the form.

BY MS. WESSLING:

Q. Okay. Well, you can go ahead and answer.

A. Not that I'm aware of.

Q. Okay. All right. I'd like to discuss the Clean Energy Connection Program with you for just a moment. Are you aware that the original Clean Energy Connection program is the subject of the appeal before the Supreme Court right now?

A. Yes.

Q. If that program were to be struck down by the Court, what would that mean for rate case?

MS. TRIPLETT: Object to the form.

THE WITNESS: I'll go with, I don't know.

BY MS. WESSLING:

Q. Five of the 14 proposed solar projects that are being proposed in this case would be included in the expansion of the company's Clean Energy Connection Program, correct?

A. That's the proposal. Yes.

Q. Looking at page 17 of your testimony, I believe that's where you described the cost effectiveness analysis that you performed for the 14 solar projects together; is that correct?

A. It looks like it, yes.

Q. All right. I think we've discussed this, but your Exhibit BMHB-3 provides the result of that analysis, correct?

A. Yes.

Q. Okay. In this particular analysis, did you model the five projects that would be part of an expansion of the CEC program any differently than the remaining nine projects?

A. No.

Q. Does this mean that the analysis treats all 14 of the proposed units as if they were pursued as a normal company resource addition rather than as an expansion of the CEC program?

A. Yes.

Q. All right. Now, on pages 18 through 20 of your testimony, has Duke Energy Florida identified which of the 14 solar projects will be a part of the CEC2 program?

A. Yes.

Q. What are those?

A. I'm going to have to look for that.

Q. Okay.

A. I think I have a list here somewhere. Since I don't seem to have a definitive list, I will tell you best information that I have off of Schedule 8 of the site plan is that those projects will be the Sundance, Bailey Mill, Half Moon, and Rattler Projects proposed for 2025 and one is yet unnamed project proposed for June of 2026.

Q. So all four of the projects that are estimated to be completed by the end of 2025 are four of the five projects that will comprise the proposed CEC2 program?

A. That is the plan, yes.

Q. Do you anticipate that the 2026 solar facility that's unnamed, is that going to be the first facility put into service in 2026?

A. We have three projects I think intended to be coming into -- maybe it's only two. Let me just double check here. Three projects intended to be coming into service around the same time in the midyear of 2026. It will be one of those. Whether it turns out to be the very first one or not, I don't know.

Q. Actually, I'm looking at the Schedule 8 of the 2024 revised 10-year site plan, and I think I only see two solar plans coming into service in 2026?

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO.: 20240025-EI

DEPOSITION OF
VANESSA GOFF

Taken on Behalf of Public Counsel

DATE TAKEN: May 29, 2024
TIME: 1:30 p.m. - 4:41 p.m.
PLACE: Video Conference

Examination of the witness taken before:

CLARA C. ROTRUCK, Court Reporter
For the Record Reporting, Inc.
1500 Mahan Drive - Suite 140
Tallahassee, Florida 32308

MS. TRIPLETT: Object to the form.

THE WITNESS: I guess I'm not understanding what you're asking.

The lease -- the facility is designed for 30 years. It should exist for 30 years. We have a lease that covers 30 years. There is an option to go longer, right? And that option would allow us to extend the life of the project by just having to pay for the lease, but not pay for -- I mean, we went beyond what the option -- when the option runs out, we wouldn't renegotiate with the landowner, I don't believe. We would remove the facility.

BY MS. WESSLING:

Q So part of the case, which tell me if you're familiar with or not, is improvements to existing (inaudible) plants to (inaudible) efficiency, right?

A I'm aware.

Q Okay. So if there were some -- let's say in 10 or 15 years, some technology came out that could allow for increased efficiency and extend the life of these solar facilities that are at these locations, and their service life was well beyond even all of the possible extensions of the lease, that's what I'm asking about is if these service lives (inaudible) beyond the longest extension possible for these leases, wouldn't

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO LATE FILED EXHIBIT REQUEST FOR REGINALD ANDERSON FROM DEPOSITION HELD ON MAY 24, 2024

3. Late-filed deposition exhibit 3: heat rate upgrade reconciliation:
   Response:
   Regarding the timing of the Osprey upgrade, DEF completed the Osprey project in 2023. Accordingly, the Osprey project is reflected in Schedule 1 of the Ten Year Site Plan (TYSP). Schedule 8 of the TYSP reflects planned and prospective generating additions as of 12/31/23. Because Osprey was completed in 2023, the Osprey heat rate project is not reflected there. Regarding the number of projects, Exhibit RDA-3 reflects the correct number of projects (eight). DEF will update Mr. Borsch's testimony to reflect eight rather than seven (page 21). Mr. Borsch inadvertently counted the two Citrus CC power blocks as one unit rather than two as reflected in Mr. Anderson's exhibit. Finally, with respect to the difference in megawatts (428 total noted in Mr. Anderson's testimony versus 400 total noted in Mr. Borsch's testimony), the difference lies in the expected output of the Hines PB 4 unit after the heat rate project. When Mr. Borsch completed his cost effectiveness analysis in 2022, and when he completed Schedule 8 of the TYSP based on information known as of 12/31/2023, the Company expected to achieve 50 MW from the heat rate project. In January 2024, the Company received an update from the OEM indicating that additional modifications could be made to the steam turbine to increase the output by an additional 28 MW. This is significant value to DEF's customers, so DEF intends to pursue that additional output and included it in Exhibit RDA-3.