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March 12, 2021

VIA ELECTRONIC FILING
Adam Teitzman, Commission Clerk
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20210015-EI
Petition by FPL for Base Rate Increase and Rate Unification

Dear Mr. Teitzman:

Attached for filing on behalf of Florida Power & Light Company ("FPL") in the above-referenced docket are the Direct Testimony and Exhibits of FPL witness Steven R. Sim.

Please let me know if you should have any questions regarding this submission.

(Document 13 of 69)

Sincerely,

R. Wade Litchfield
Vice President & General Counsel
Florida Power & Light Company

RWL:ec

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. 20210015-EI

MARCH 12, 2021

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Steven R. Sim. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL") as the Director of Integrated Resource Planning.

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

A. I direct and perform resource planning analyses for FPL including the former service area of Gulf Power Company ("Gulf"). These analyses are largely designed to determine the magnitude and timing of resource needs for a given utility system and then develop the integrated resource plan with which those resource needs will be met. The analyses are also designed to identify ways through which to improve system economics and/or enhance system reliability for customers.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Miami (Florida) with a bachelor's degree in Mathematics in 1973. I subsequently earned a master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles ("UCLA") in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977 - 1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable energy resources applicable in the Southeastern United States, including photovoltaics, biomass, and wind power.

In 1979, I joined FPL. From 1979 until 1991, I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness analyses of demand side management ("DSM") programs. In 1991, I joined my current department, then named the System Planning Department, where I held different supervisory and/or managerial positions dealing with integrated resource planning ("IRP"). I assumed my present position in 2017.

Q. Have you previously testified on resource planning issues before the Florida Public Service Commission?

A. Yes. I have testified before the Florida Public Service Commission ("FPSC") in numerous dockets. These dockets have dealt with a variety of issues such as system reliability and economic analyses of many types of resource options. Among the specific subjects addressed in those dockets are: (i) need determination filings for new combined cycle ("CC") units, advanced coal units, and nuclear units, (ii) nuclear feasibility analyses, (iii) DSM Goals and programs, (iv) economics of utility DSM programs, (v) economics of solar and battery storage, and (vi) economics of competing generation and transmission options, particularly in regard to meeting regional needs.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- SRS-1 With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis;
- SRS-2 Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs;
- SRS-3 Comparison of Resource Plans: W/ 2022 Manatee Changes and W/ 2029 Manatee Changes;
- SRS-4 Load Forecasts Used in the Current Analyses;
- SRS-5 Fuel Cost Forecasts Used in the Current Analyses;
- SRS-6 CO_2 Compliance Cost Forecast Used in the Current Analyses;
- SRS-7 Results of the Initial Step 1 and Step 2 Analyses;
- SRS-8 Results of the Current Step 1 Analysis;
- SRS-9 Results of the Current Step 2 Analysis;
- SRS-10 Projected CPVRR Costs for: the NFRC Line Project[1], Wheeling Through the Southern Company System, and Wheeling Through the Duke Energy Florida ("DEF") System;

[1] From a resource planning perspective, the North Florida Resiliency Connection ("NFRC") is a project that consists of a new transmission line plus other components. The various components are discussed later in Section VI of my testimony. For simplicity, references to the NFRC project that appear elsewhere in the testimony will use the term "NFRC".

- SRS-11 FPL Stand-Alone Resource Plan Developed in the Current Step 2 Analyses;
- SRS-12 Results of the Current Step 3 Analyses; and,
- SRS-13 Economic Analysis Results for the Planned 2022 and 2023 Solar Additions.

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. No.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. No.

Q. In your testimony, how will you reference the former two utility systems: FPL and Gulf Power?

A. In my testimony I will discuss analyses of both the former Gulf Power ("Gulf") system and of the FPL system prior to the merger of the two utility systems. I will also discuss analyses of the single integrated system which I will refer to as FPL. When discussing the single integrated FPL system, I will also use the terms "FPL area" and "Gulf area" to refer to the former service areas for each utility. These geographic area references are used to denote the siting of various planned resource additions, particularly solar additions.

Q. What is the purpose of your testimony, and how is it organized?

A. The purpose of my testimony is to address six (6) main topics that will be discussed in the following order:

- Topic #1: Appropriate new monthly incentive payment levels for two of FPL's largest DSM programs: the Commercial/Industrial Demand Reduction ("CDR") and Commercial/Industrial Load Control ("CILC") programs;
- Topic #2: The Manatee Modernization Project;
- Topic #3: The three-step approach used to perform resource planning analyses of the previous Gulf and FPL systems, plus the new integrated single system;
- Topic #4: Results of initial analyses with a focus on near-term changes/additions for the Gulf system of generating units;
- Topic #5: Results of the current analyses with a focus on connecting the Gulf and FPL systems with the NFRC; and,
- Topic #6: Results of the current analyses with a focus on integrating the Gulf and FPL systems/areas into a single utility system, including planned solar additions for 2022 through 2025.

Q. Please summarize your testimony.

A. I will summarize my testimony in terms of each of the six topics listed above.

<u>Topic #1: Appropriate new monthly incentive payment levels for FPL's CDR and CILC programs:</u>

Two of FPL's DSM programs, the CDR and CILC programs, are no longer cost-effective[2] at current levels of monthly incentive payments to program participants. This situation is the result of two trends that have been occurring over the last decade: (i) the incentive payment levels have steadily increased, thus increasing the cost of the programs; and, at the same time, (ii) the benefits of utility DSM programs (including CDR and CILC) have been declining. (Both of these trends are discussed later in my testimony). As a result, the incentive payment levels for both programs need to be adjusted downward in order to return the programs to a position that is not only cost-effective now, but also offers reasonable assurance that the programs will remain cost-effective for all customers over the next 4-to-5 years when the incentive levels are likely to be reviewed again.

FPL proposes to lower the monthly incentive payment for the CDR program from its current level of $8.71/kW to $5.80/kW. In regard to the CILC program, its incentive payment is accounted for by a percentage reduction in a participant's base bill relative to the standard rate. As a result, adjusting the current CILC incentive downward commensurate with the proposed reduction for the CDR program is handled in rate design. FPL witness Cohen will address the appropriate adjustment in the CILC incentive payment in her testimony.

[2] Cost-effective means the projected net present value of benefits are equal to/greater than the projected net present value of costs using the Rate Impact Measure ("RIM") economic screening test; *i.e.*, a RIM ratio of at least 1.00. The CDR and CILC programs combined currently have a RIM benefit-to-cost ratio of 0.97 as discussed in Section II of my testimony.

Notably, the proposed new incentive level is still higher than the incentive levels that existed when approximately 75% of the existing CDR, and 100% of the existing CILC, program participants enrolled in the programs. Furthermore, the proposed new incentive level is higher than the incentive available under Gulf Power's commercial/industrial load management program in which Publix has recently signed up two dozen stores as participants. Therefore, the proposed new CDR incentive level should be more than sufficient to enable FPL to meet its approved DSM Goals regarding new participants in this program while retaining existing participants.

<u>Topic #2: The Manatee Modernization Project:</u>

The Manatee Modernization Project consists of two main components that are planned to be completed in the fourth Quarter of 2021. These two components are: (i) the retirement of the existing Manatee steam Units 1 & 2; and (ii) the installation of a large, nominal 400 MW, 2.2 hour duration battery storage facility at the Manatee plant site that will provide firm capacity and will, in part, replace the generation capacity that will be removed with the retirement of Manatee Units 1 & 2.

The annual capacity factors for the two Manatee units have been steadily declining while the annual capital and operations and maintenance ("O&M") costs have remained at a significant level. This led to analyses in 2018 and 2019 that showed a retirement of the two units in the fourth Quarter of 2021 was projected to be cost-effective for customers by $101 million cumulative present value of revenue requirements ("CPVRR"). The capacity that is removed due to retiring these two units was projected to be replaced, over several years as needed, by a combination of the nominal 400 MW battery storage facility and the acceleration of solar and CC projects.

<u>Topic #3: The three-step resource planning analysis approach used to analyze the previous Gulf and FPL systems, and the single integrated system:</u>

Given the acquisition of Gulf by NextEra Energy, Gulf is scheduled to exit the Southern Company system no later than January 2024. As a result, new resource planning analyses for Gulf were required, and an analytical approach was developed to examine a number of potential improvements to the generation and/or transmission systems for the former Gulf service area and the new larger FPL service area in order to benefit customers in all areas. This analytical approach consists of three steps that were performed sequentially.

Step 1 was designed to evaluate potential changes/additions to Gulf's generation system assuming Gulf remained a stand-alone system without committed support from Southern Company and without any new transmission linkage to FPL. Step 2 was designed to evaluate the economics of the NFRC [3] assuming that both Gulf and FPL remained as separate utility systems. Step 3

[3] Details of the NFRC are presented in FPL witness Spoor's testimony.

was designed to evaluate the economics of combining the Gulf and FPL systems into a single integrated utility system which is made possible by the NFRC.

My testimony presents results from the initial analyses performed in late 2018/early 2019 that led to decisions regarding near-term (2020-2024) changes/additions to Gulf's system of generation units. My testimony also presents results from the current analyses that focus primarily on the NFRC and the integration of the Gulf and FPL systems.

Topic #4: Results of initial analyses with a focus on near-term resource changes/additions for the Gulf generation system:

The initial analyses primarily focused on Steps 1 and 2 of the three-step approach. In the initial Step 1 analyses, a number of potential changes/additions to Gulf's system were found to be cost-effective and, in total, were projected at the time to result in CPVRR savings to Gulf's customers of $691 million.

Then the initial analyses using Step 2 of the analytical approach examined two things: (i) whether the NFRC would result in additional net cost savings for Gulf's customers, and (ii) whether the changes/additions to the Gulf generation system identified as cost-effective in the initial Step 1 analyses were still projected to be cost-effective if the NFRC was added. These initial Step 2 analyses showed at the time that the NFRC was projected to result in additional net CPVRR savings of $194 million[4] for Gulf's customers. These initial analyses also confirmed that several of the changes/additions that had been identified as cost-effective in Step 1 were again projected to be cost-effective in Step 2 after assuming the NFRC was in place. Thus, these changes/additions were projected to be cost-effective for Gulf's customers both with and without the NFRC. As a result, Gulf decided to proceed with several of those changes/additions to their system of generating units that would occur in the near-term (2020 and 2021). These include: (i) an approximately 80 MW upgrade to the Lansing Smith CC unit, (ii) the coal-to-gas conversion of the Crist Units 6 & 7[5], (iii) the addition of three approximately 75 MW solar facilities, and (iv) the addition of 4 CT units of 235 MW each.[6]

<u>Topic #5: Results of the current analyses with a focus on connecting the Gulf and FPL systems with the NFRC:</u>

In the current analyses which occurred in the second half of 2020/early 2021, the four changes/additions to the Gulf generation system that were just mentioned were assumed to be a "given" in the development of any resource plan. In addition, numerous forecasts (load, fuel cost, etc.) and assumptions

[4] The $691 million and $194 million CPVRR savings values from the initial analyses were based on then current forecasts and assumptions. In subsequent analyses, these forecasts and assumptions were updated. As a result, the $691 million and $194 million CPVRR values are superceded/replaced by the results of new current analyses and are <u>not</u> additive to the results of the current analyses.

[5] The Crist plant has recently been renamed as the Gulf Clean Energy Center. However, references to the generating units at this site in my testimony are from earlier analyses of Gulf Power as a separate utility system. Therefore, my testimony will reflect the Crist name of the units that were applicable when the analyses were performed.

[6] At the time this testimony is filed, the Lansing Smith upgrade, the Crist coal-to-gas conversion of Units 6 and 7, and one of the new solar facilities have already been completed. Work on the other two solar facilities and the four CTs is underway.

(cost of capital, discount rate, etc.) were updated. NFRC-related costs, transfer limits, and the NFRC's in-service date were also updated. The analysis period was expanded from 2019 - 2048 to 2020 - 2068 as well. (This change in the term of the analysis period will be discussed later in my testimony).

Due to the updated forecasts and assumptions, a new Step 1 analysis was performed in order to provide an updated, optimized Gulf stand-alone resource plan from which to again evaluate the NFRC. This current Step 1 analysis shows that, over and above the Gulf generation system changes/additions that were taken as a given, improvements to Gulf's generation system are now projected to result in $856 million in CPVRR cost savings for Gulf's customers compared to a "business as usual" resource plan that builds only natural gas-fueled new generating units. Then the current Step 2 analysis shows that the NFRC is expected to result in an additional $389 million CPVRR of net savings for Gulf customers after accounting for NFRC costs.[7]

Thus, the current Step 1 and Step 2 analyses are projecting a total net savings of $1,245 (= 856 + 389) million CPVRR for Gulf's customers.[8] In addition, the projected total cost of the NFRC, $722 million CPVRR, is approximately 44% lower than the projected lowest cost alternative, $1,282 million CPVRR, of

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[7] The current analyses account for all known/projected system costs and cost impacts at the time this testimony is filed. Although other potential costs might be identified at a later date, the magnitude of the current projected net benefits provides confidence that the projected net benefits will remain significant even if other potential costs are identified.

[8] As indicated in an earlier footnote, the $856 million and $389 million CPVRR savings values from the current analyses supersede/replace the $691 million and $194 million CPVRR savings values previously projected in the initial analyses.

wheeling the same amount of capacity and energy through existing transmission systems of other utilities.

Topic #6: Results of the current analyses with the focus on integrating the Gulf and FPL systems, including the planned solar additions for 2022 through 2025:

An integration of the Gulf and FPL systems is going to allow FPL and Gulf to take advantage of certain factors that result in lower costs for customers. Among these are: (i) the coincident Summer peak hour load, and the coincident Winter peak load, for the integrated system are lower than the sum of the peak hour loads for each separate utility; and (ii) the 20% total reserve margin criterion now has to be met only for the integrated system, not separately for each utility's former service area (the Gulf area and the FPL area). These factors result in less new generation capacity having to be built to meet the reserve margin criterion which, in turn, lowers future fixed costs for new generation that would otherwise be needed.

The current analyses also include a Step 3 analysis of the economics of a single, integrated utility system. The current Step 3 analysis projects an additional $288 million CPVRR cost savings for customers beyond the projected total CPVRR savings of $1,245 million from the current Steps 1 and 2 analyses. This brings the projected total net CPVRR savings for customers from the current Steps 1 through 3 analyses to $1,533 (= 1,245 + 288) million. These savings are summarized in Table SRS – Summary below.

Table SRS-Summary
Summary of Results from the Current Steps 1 through 3 Resource Planning Analyses

Analysis Step	Focus of Analysis Step	Projected Net Savings (CPVRR, millions)	Projected Cumulative Net Savings (CPVRR, millions)	Comments
Step 1	Value of near-term improvements (changes/additions) to Gulf's system of generation units	856	856	The value shown does not account for the projected savings for several changes/additions to Gulf's generation system that were selected based on the initial analyses and which are either already in place or are in progress.
Step 2	Additional value of connecting Gulf and FPL via the NFRC	389	1,245	Net savings value accounts for the projected costs of the NFRC.
Step 3	Additional value of integrating the Gulf and FPL systems into a single utility system	288	1,533	These additional savings are made possible by the addition of the NFRC. The NFRC is directly or indirectly responsible for a projected $677 million CPVRR savings (= 389 + 288).

Note: CPVRR net savings projections shown in the 3rd and 4th columns are for the years 2020 through 2068

As shown in the Comments section of the last row of this table, the NFRC – which is needed to connect and integrate the two systems – is directly or indirectly responsible for a projected customer savings of $677 (= 389 + 288) million CPVRR, which represents approximately 44% of the projected total CPVRR net savings of $1,533 million, or approximately $1.5 billion.

Almost 3,000 MW (nameplate) of new solar facilities are projected to be installed in the single integrated system in the 2022 through 2025 time period. Those solar facilities are included in the resource plan for the integrated

FPL/Gulf system that emerged from the current Step 3 analysis. Due to the integration of the two systems, approximately 38% of the almost 3,000 MW of solar being added is planned to be sited in Gulf's former service area which contributes to the projected total cost savings.

Included in FPL's request for cost recovery in this docket, FPL is seeking approval to recover costs for solar facilities to be installed in 2022 and 2023. The projected CPVRR savings from adding only these planned solar facilities in 2022 and 2023, assuming no more solar is added thereafter, is $397 million. FPL is also requesting approval of a solar base rate adjustment ("SoBRA") mechanism to allow FPL to seek cost recovery and adjust base rates accordingly at a later date for solar facilities to be installed in 2024 and 2025. FPL witness Valle discusses this SoBRA mechanism in his direct testimony. At the time this testimony is filed, specific sites (Gulf's former service area and/or the rest of FPL's service area) and solar technology (fixed tilt and/or tracking) for the 2024 and 2025 solar additions have not yet been determined. This information is needed before final economic analyses of the planned 2024 and 2025 solar additions can occur. However, that specific information regarding sites and technology will have been determined, and subsequent economic analyses will have occurred, prior to a future cost recovery filing regarding 2024 and 2025 solar additions.

II. APPROPRIATE NEW INCENTIVE PAYMENT LEVELS FOR CDR & CILC

Q. Please briefly describe the CDR and CILC programs.

A. The CDR and CILC programs are FPL's largest DSM programs for commercial and industrial customers. Voluntary participants in these programs agree to allow FPL to remotely lower a portion of the participant's served electric load as needed (for example, during a period of high electrical demand on FPL's system) in exchange for the participant receiving a reduction in their monthly bill. The bill reduction will be referred to in my testimony as a monthly incentive payment.

The two programs have a combined demand reduction capability of slightly more than 800 MW.[9] The CDR program is open to new participants. The CILC program was officially "closed" to new participants in the year 2000 and was essentially replaced by the CDR program which offers a similar load management program to CI customers.

Q. What are the current incentive payment levels for the two programs?

A. The incentive payments are administered differently for each program. For the CDR program, the incentive is administered as a $/kW credit on the monthly bill. The current CDR program monthly incentive is $8.71/kW. For the CILC program, the incentive is administered as a percentage reduction of the base

[9] As of year-end 2020, the total MW reduction capability at the generator for the two programs combined at the August peak load hour was approximately 814 MW consisting of 466 MW of CILC and 348 MW of CDR.

bill. At the end of 2020, the current CILC program incentive averaged out to be approximately a 22% reduction in a participant's base bill compared to the otherwise standard rate.

Q. Are you proposing changes to monthly incentive payments for both programs? If so, are you presenting the proposed changes to incentive payments in both of the two incentive payment formats: $/kW and percentage reduction of the base bill?

A. Yes, changes to the monthly incentive payments for both the CDR and CILC programs are proposed. However, I will be discussing the proposed changes in incentive payments only in terms of a $/kW payment format. The reason for this is that when discussing any potential changes to the CILC program's incentive payment in terms of a percentage reduction of the base bill, rate design issues are involved. These issues are best addressed by an individual with expertise in electric rate design such as FPL witness Cohen. In her direct testimony, FPL witness Cohen will discuss how she reviewed the results of the analyses I discuss and then developed an appropriate percentage reduction in the base bill for the existing CILC participants.

Q. How large a factor are the incentive payments in regard to the overall costs of the programs?

A. The programs have three cost components: (i) administrative costs, (ii) unrecovered revenue requirements, and (iii) monthly incentive payments. Using the CDR program as an example, the monthly incentive payments account for slightly more than 97% of the projected total CPVRR cost of the CDR program.

Consequently, the monthly incentive payment is the primary "driver" of program costs.

Q. Does FPL periodically evaluate the cost-effectiveness of its DSM programs?

A. Yes. FPL's IRP group periodically performs cost-effectiveness analyses of "open" DSM programs (*i.e.*, programs that are open to new participants), including the CDR program, and/or potential new DSM programs. These cost-effectiveness analyses typically focus on whether it is cost-effective to sign up new participants for the DSM program in question using the Commission's approved cost-effectiveness methodology.

Some of these analyses are driven by regulatory requests. For example, the FPSC Staff has frequently requested updated cost-effectiveness analyses of open DSM programs, including the CDR program, as part of annual Florida Energy Conservation Cost Recovery Clause ("ECCR") filings. The most recent filing was the ECCR True Up filing in May 2020 (Docket No. 20200002). Analyses of the cost-effectiveness of DSM measures and programs are also typically performed in the DSM Goals/DSM Plan dockets that occur every five years.

Q. Why is FPL discussing these two programs in this docket?

A. On February 24, 2020, FPL filed a petition for FSPC approval of its DSM Plan. One of the existing programs that is "open" to new participants which was included in FPL's DSM Plan was the CDR program. Included in FPL's DSM

Plan filing was a projection of the cost-effectiveness of signing up new participants for each program using the three preliminary cost-effectiveness screening tests called for in the FPSC's approved cost-effectiveness methodology. These three screening tests are: (i) the Rate Impact Measure ("RIM") test, (ii) the Total Resource Cost ("TRC") test, and (iii) the Participant test. The projected benefit-to-cost ratios for signing up new participants for each program was summarized on page 7 of the DSM Plan.

For the CDR program, the projected benefit-to-cost ratio under the RIM test for signing up new participants was 1.36.[10] However, as was explained on this same page of the DSM Plan, this benefit-to-cost ratio of 1.36 assumed a reduction in the CDR monthly incentive payment from the current level of $8.71/kW to $6.09/kW. Also on that page was an explanation that *"…(without this reduction, the RIM ratio would drop to 0.97)."* In other words, signing up new CDR participants at the current incentive level was projected to no longer be cost-effective in February 2020.

In that docket, a decision was ultimately made by the FPSC to not address CDR (and CILC) incentives at that time, but to defer the decisions on these incentive levels to FPL's next base rate case, *i.e.*, to this docket.

[10] The projected benefit-to-cost ratio for the CDR program under the TRC test was 49.26. This very high benefit-to-cost ratio highlights one of the fundamental flaws of the TRC screening test: the TRC test does not account for utility incentive payments to DSM participants and, therefore, provides misleading and inaccurate results.

Q. Has signing up new participants for the CDR program been projected to be cost-effective in years prior to the February 2020 DSM Plan filing?

A. Yes. This can be seen by a look back at previous years' results of RIM test analyses of signing up new CDR participants. For example, in FPL's 2010 DSM Plan filing, the projected benefit-to-cost ratio for signing up new CDR participants was 3.10. This analysis was based on the incentive levels in place at the time (and prior to the 2012 base rate case settlement agreement that increased the incentive levels). It meant that at the then current monthly incentive levels (of $4.68/kW), which were sufficient to attract participants into the program, the general body of customers were realizing substantial benefits.

In the 2015 DSM Plan filing, the projected benefit-to-cost ratio had dropped to 1.62. Although this lower benefit-to-cost value in 2015 shows a significant decline in cost-effectiveness from 2010, signing up new participants was still projected to be cost-effective in 2015, but with measurably less value for the general body of customers.

Five years later, in FPL's February 2020 DSM Plan filing, signing up new participants with the current CDR incentive level was no longer projected to be cost-effective as previously mentioned. A summary of these declining benefit-to-cost ratios, and applicable incentive levels at the time, is shown below in Table SRS-1.

Table SRS-1
CDR Benefit-to-Cost Ratios for
Signing Up New Participants: 2010 - 2020
(with then current incentive levels)

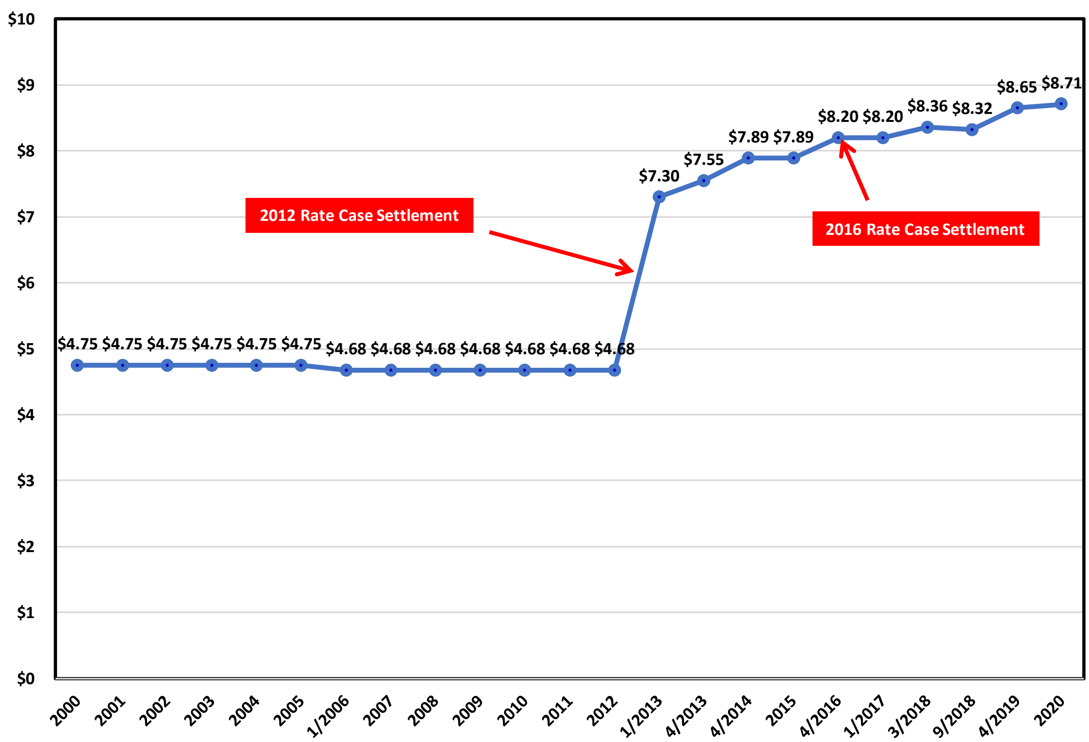
Year of Analysis	Benefit-to-Cost Ratio	CDR Incentive ($/kW-month)
2010 (DSM Plan)	3.10	$4.68
2015 (DSM Plan)	1.62	$7.89
2020 (DSM Plan)	0.97	$8.71

Q. What has caused this decline in CDR cost-effectiveness?

A. There are two reasons for this. One is that CDR's $/kW monthly incentive payment level almost doubled from 2010 to the present as shown above in the right-hand column of Table SRS-1. The year-to-year growth over time of the CDR incentive level is shown below in Figure SRS-1.

Figure SRS-1

History of CDR Incentives: 2000 to Present



As shown in Figure SRS-1, the CDR $/kW monthly incentive level first increased from $4.68 to $7.30 as a result of a comprehensive settlement in FPL's 2012 base rate case. Subsequent increases in the CDR incentive payment level to its current level of $8.71/kW occurred due to base rate increases provided by the 2012 and 2016 settlement agreements. Due to these increases in the incentive payment level, the cost of the CDR program for non-participant customers has increased greatly.

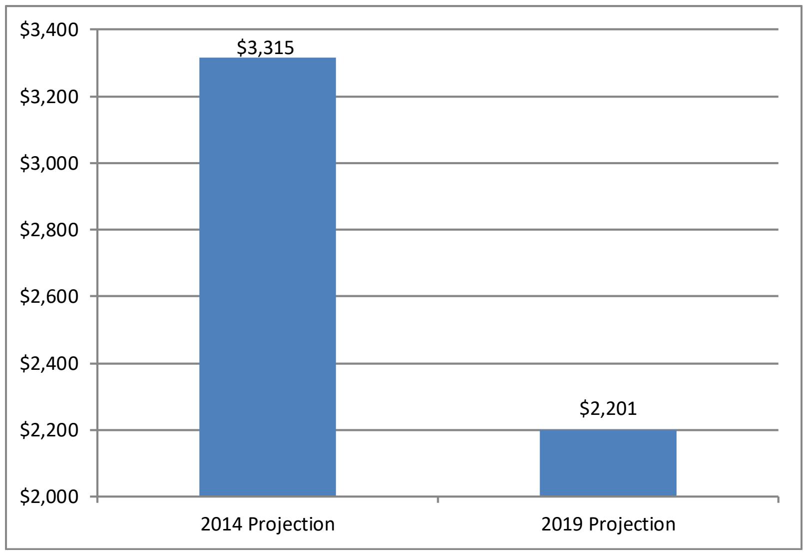
In addition, during the years in which the monthly incentive $/kW payment levels were increasing, a number of other utility costs that potentially could be avoided by DSM programs (*i.e.*, the benefits of DSM) have been trending steadily downward. Although this trend is a very good one overall for FPL's customers, it significantly lowers the potential benefits of utility DSM programs.

This trend of declining utility costs that potentially could be avoided by DSM was discussed at length in my direct testimony in the 2019 DSM Goals docket (Docket No. 20190015-EG). This testimony described how a number of costs that are potentially avoidable by DSM (natural gas costs, capital costs of new generation, etc.) have significantly decreased.

This trend of declining utility costs that are potentially avoidable by DSM has resulted in a significant decline in the benefits side of DSM benefit-to-cost analyses (regardless of which of the preliminary cost-effectiveness screening tests with an all utility customer perspective, RIM or TRC, is used). This was summed up in my 2019 DSM Goals testimony by a comparison of projected DSM benefits for a proxy DSM measure that was developed first using 2014 forecasts and assumptions, then using 2019 forecasts and assumptions. In this comparison, the DSM measure's projected kW and kWh reduction per participant values did not change. This comparison was presented on page 36 of my direct testimony in that docket. It is repeated below in Figure SRS-2.

Figure SRS-2

Projected Total Benefits for both the RIM and TRC Screening Tests for the Proxy DSM Measure Using 2014 and 2019 System Cost Values (CPVRR, $000)



As shown in this figure, the projected CPVRR benefits for the proxy DSM measure decreased from approximately $3.3 million to $2.2 million, or approximately 33%, from 2014 to 2019. This trend of declining DSM benefits negatively affects all DSM programs, including the CDR and CILC programs (even though the CILC program is not open to new participants).

By February 2020, when FPL's DSM Plan was filed, the combination of increased CDR incentive payment levels, and lower benefits for the program, resulted in the CDR program no longer being cost-effective in regard to signing up new participants at the current incentive level.

Q. Has FPL conducted an updated study since February 2020 of the cost-effectiveness of signing up new CDR participants?

A. Yes. In that regard it is helpful to note that FPL's analyses performed first for the 2019 DSM Goals filing, then the subsequent 2020 DSM Plan filing, used a set of forecasts and assumptions that were consistent with those used to develop FPL's 2019 Ten Year Site Plan ("TYSP"). Since that time, almost all of the forecasts and assumptions that FPL uses in its IRP work have been updated at least once. Because so much information has been updated, a fresh analysis of the cost-effectiveness of signing up new CDR participants was performed. Due to the above-mentioned trends, the projected economics of new CDR participants using the current monthly incentive level of $8.71/kW has worsened further, and the resulting benefit-to-cost ratio is now 0.45 as shown below in Table SRS-2. Thus, the projected economics of signing up new CDR participants is now significantly worse than had been projected at the time of the February 2020 DSM Plan filing.

Table SRS-2
CDR Benefit-to-Cost Ratios for
Signing Up New Participants: 2010 - 2020
(with then current incentive levels)

Year of Analysis	Benefit-to-Cost Ratio	CDR Incentive ($/kW-month)
2010 (DSM Plan)	3.10	$4.68
2015 (DSM Plan)	1.62	$7.89
2020 (DSM Plan)	0.97	$8.71
2020 (New Analysis)	0.45	$8.71

In summary, it is currently not cost-effective to sign up new CDR customers at the current incentive level. This outcome is simply the result of the two previously discussed trends, increasing incentive payments and declining DSM benefits, that have been occurring over the last decade.

Q. Do analyses of the cost-effectiveness of signing up new participants, such as those discussed above, fully capture the impact of the CDR program?

A. No. An additional analysis is needed to fully capture the system impact of the CDR program. This is because the vast majority of total CDR participants are not new participants who will be signing up for the program in the future, but are existing CDR participants who are receiving monthly incentive payments at the current level of the CDR incentives. In addition, although there will be no new signups to the closed CILC program, there are also existing CILC program participants who are receiving monthly incentive payments. Recognizing this, FPL conducted another analysis which addressed both existing participants for the CDR and CILC programs as well as projected new CDR participants.

Q. Please explain the approach used for this analysis that included existing CDR and CILC participants.

A. For this analysis, an approach was used that compared the economics of two resource plans. Both resource plans were developed using the AURORA optimization model. One resource plan, the "With Programs" plan, is the same resource plan that will be presented in the FPL/Gulf 2021 TYSP and discussed again later in my testimony in regard to the current Step 3 analysis. This plan assumes that all of the approximately 800 MW of demand reduction capability from existing CDR and CILC participants, and the approximately 10 MW per year of projected new CDR participants shown in FPL's approved DSM Plan, are in this resource plan. However, for purposes of this analysis, the projected monthly incentive payments for both existing and new participants were zeroed out. As a result, the "With Programs" resource plan accounts for all of the demand reduction benefits of the CDR and CILC programs, but assumes no incentive payment costs.

The second resource plan, the "Without Programs" plan, assumes that all of the existing CDR and CILC MW, all projected new CDR signups, and all incentive payments for both programs are removed from the plan starting in January 2022.[11] The AURORA model then selected the most cost-effective generation resources to replace the loss of 800+ MW of demand reduction capability.

The two resource plans, and the projected CPVRR costs for each plan, are presented in Exhibit SRS-1.[12] The projected CPVRR costs of the two resource plans were then compared. As one would expect, the projected CPVRR cost of the Without Programs resource plan, $82,796 million, is higher than the projected CPVRR cost of the With Programs resource plan, $81,942 million,

[11] Note that the use of the January 2022 "exit" date assumption means all existing participants in the CDR and CILC programs would exit the programs with less than one year's notice (which ignores the 5-year exit notice terms for both programs). Because of this assumed sudden loss of 800+ MW of demand reduction capability, replacement capacity needs to be added relatively quickly. As a result, the January 2022 exit assumption maximizes the projected value of the two programs for purposes of this analysis.
[12] These resource plans, and all other resource plans presented in my testimony that include resources sited in FPL's former service area, include planned upgrades to combustion turbine components of CC units in addition to the resource additions shown in each plan. These upgrades are discussed in FPL witness Broad's direct testimony.

because the Without Programs resource plan needed to add new resources to make up for the loss of the 800+ MW of demand reduction capability offered by the CDR and CILC programs.

The $853 (= 82,796 – 81,942) million CPVRR differential represents the projected benefits of the CDR and CILC programs. As such, it also represents – after accounting for the administrative costs of the CDR and CILC programs – the amount of CPVRR expenditure that can be paid in the form of monthly incentive payments to CDR and CILC participants in the With Programs resource plan and have an identical CPVRR cost for both of the resource plans (assuming that there will be no future changes to the current projections of CDR and CILC benefits or program administrative costs.)[13]

Q. Starting with the $853 million CPVRR differential value as the starting point from which to evaluate CDR and CILC incentive payments, what other considerations were taken into account when developing the proposed new monthly incentive payment for the two programs?

A. Four other considerations were initially taken into account in establishing the proposed incentive payment levels for the programs. The first consideration for any DSM program, including these two programs, is that the maximum incentive level that should be considered is one that results in program costs exactly equaling program benefits (*i.e.*, a RIM benefit-to-cost ratio of 1.00). Such a result typically means - assuming that there are no future changes in

[13] The total CPVRR administrative cost for these programs is projected to be approximately $8 million.

projected programs benefits or costs - that program participants will benefit from the program and that the utility's general body of customers should be indifferent regarding whether the program is offered because electric rates are unchanged compared to what would be the case if the DSM program had not been offered and the best generation alternative had been chosen instead.

The second consideration is that, all else equal, it is preferable to have a DSM program's RIM benefit-to-cost ratio greater than 1.00. In such a case, all customers will benefit from the DSM program, not just the program participants, again assuming there are no future changes in projected program benefits or costs. Therefore, all else equal, it is preferable to utilize an incentive that is lower than the maximum incentive payment level to ensure that the general body of ratepayers also benefit from the DSM program.

The third consideration is based on the fact that, contrary to the assumption mentioned above in regard to the first two considerations, the projected benefits and costs for DSM programs <u>do</u> change over time. As discussed earlier, the trends over the last decade have clearly been declining DSM program benefits and increasing CDR incentive costs. Thus when developing an appropriate incentive level for CDR and CILC, it would be wise to set the incentive level low enough to ensure that the programs remain cost-effective if the current trend of declining DSM cost-effectiveness continues.

The fourth consideration is that incentive levels for CDR and CILC are typically reset only in DSM Goals and/or rate case dockets. DSM Goals dockets are spaced 5 years apart and recent FPL rate case filings have been spaced 4 to 5 years apart. Therefore, the setting of incentives for these two DSM programs should strive to ensure that the programs will remain cost-effective for a minimum of 4 years.

Q. Taking these four considerations into account, how did FPL decide upon a proposed new incentive level for these programs?

A. First, certain calculations were performed to judge the cost-effectiveness of the current CDR monthly incentive level of $8.71/kW. These calculations are presented in Exhibit SRS-2. The left hand side of this exhibit presents a number of assumptions used in the calculations. Assumption (1) is the CPVRR difference between the With Programs resource plan and the Without Programs resource plan that appears in Exhibit SRS-1: $853 million. Assumption (2) is the projected CPVRR administrative cost of the combined CDR and CILC programs: $8 million. Assumption (3) is the current monthly incentive level for CDR of $8.71/kW. Assumptions (4) through (7) present other information used in calculations whose results are shown on the rest of this exhibit.

The right hand side of the exhibit presents a table that shows the results of calculations for two scenarios. In Scenario 1, the projected RIM benefit-to-cost ratio for the 800+ MW of CDR and CILC with the current monthly incentive level of $8.71/kW is shown: 0.97. This result shows that the programs, even after accounting for the demand reduction capability of their existing participants, are no longer projected to be cost-effective with the current monthly incentive level.

Based on the projection that the programs are no longer cost-effective with the current monthly incentive level, and the considerations discussed above, FPL decided that it was appropriate to reset the monthly incentive level at $5.80/kW. Scenario 2 in Exhibit SRS-2 shows the same calculations for the programs with this proposed monthly incentive level. The result is that the projected RIM benefits-to-cost ratio has increased to 1.45. Thus, the proposed monthly incentive level should provide a reasonable level of assurance that the programs will remain cost-effective for all customers for the expected 4-to-5-year period until the incentive levels are next reviewed.

Q. How does the proposed monthly incentive level compare to the incentive level that existed at the time most of the CDR participants joined the program and to the incentive level currently offered by Gulf's load management offering for commercial/industrial customers?

A. These were two additional considerations that were taken into account when deciding to propose a monthly incentive of $5.80/kW. Approximately 75% of the existing CDR participants joined the program during the time period when the monthly incentive was initially $4.75/kW, then decreased to 4.68/kW, as depicted previously in Figure SRS-1. The proposed new CDR monthly incentive level of $5.80/kW is more than 20% higher than the incentive level that was in place when the majority of CDR participants joined the program. In regard to Gulf's load management offering for commercial/industrial customers, the Curtailable Load Rider offers a $5.57/kW monthly incentive that remains constant for a 10-year period. At the time this testimony is written, two dozen Publix stores have signed up for this offering.

Therefore, FPL concludes that the proposed new incentive level is not only projected to return the programs to a current cost-effective position, this proposed new incentive level will also be sufficient to help ensure the cost-effectiveness of the CDR and CILC programs for a 4-to-5 year period, achieve future CDR program participation needed to meet FPL's approved DSM Goals, and to retain existing CDR and CILC participants.

III. THE MANATEE MODERNIZATION PROJECT

Q. What is the Manatee modernization project?

A. The Manatee modernization project has two main components. One component is the planned retirement of FPL's existing Manatee steam Units 1 & 2 in the fourth Quarter of 2021. The second component is the installation of a large, nominal 400 MW, 2.2 hour duration battery storage facility at the Manatee plant site. The battery is designed to provide firm capacity to replace, in part, the generation capacity that will be removed with the retirement of Manatee Units

1 & 2. The battery storage facility is scheduled to be in-service in the fourth Quarter of 2021.

Q. Why are the existing Manatee Units 1 & 2 being retired?

A. The decision to retire these units was based on projected cost savings for FPL's customers. The existing Manatee units were brought into service more than 40 years ago.[14] Although these steam units were considered fuel-efficient at the time they went into service, their heat rates are in excess of 10,000 BTU/kWh which means that these two generation units are now quite inefficient compared with modern generating units. Due to continued upgrading, FPL's fossil-fueled generation fleet now has an average heat rate of slightly under 7,000 BTU/kWh. As a result, the two Manatee units no longer operate as baseload units as they once did, and the capacity factors for the two Manatee units have decreased over time. For example, the two units operated at capacity factors of approximately 17% during 2020. In addition, the projected average capacity factors for the two units for the years 2022 through 2028, assuming the units continue to operate, are expected to decrease further to a range of only 10% to 13%. Thus while the two 800 MW units continue to provide system reliability, their day-to-day operational value has diminished.

Although the units are not operated much, the annual capital costs and costs of operating and maintaining the two units remain significant. For example, for the years 2014 through 2018, the average annual combined capital and O&M

[14] The in-service dates were October 1976 for Manatee Unit 1 and December 1977 for Manatee Unit 2.

cost was approximately $36 million per year. Taking into account both the declining operating hours and these significant annual costs for the two units, analyses were performed to see if an early retirement of the two units would be economically beneficial for FPL's customers. These analyses examined an earlier retirement versus a then projected retirement date for the two units of late 2028/beginning of 2029 (at which time the units would have been operating for more than 50 years).

Q. How much generating capacity is removed with the retirement of Manatee Units 1 & 2?

A. Both Manatee Units 1 & 2 have a Summer capacity rating of 809 MW. Therefore, the retirement of both units will remove 1,618 MW of Summer generating capacity from FPL's system. The combined Winter generating capacity for the two units is similar: 1,638 MW.

Q. Does all of this removed capacity need to be replaced as soon as the existing Manatee units are retired?

A. No. The amount of capacity that would have to be replaced immediately depends upon the projected reliability of the system, based primarily on Summer reserve margin criteria for the FPL system, without the 1,618 MW of removed Summer capacity.

Q. What date was chosen as the early retirement date for the analyses, and why was it chosen?

A. An early retirement date of fourth Quarter 2021 was chosen for the analyses for a couple of reasons. First, largely due to the addition of the new 1,163 MW CC unit at FPL's Dania Beach site by Summer of 2022, the opportunity arose for FPL to meet its 20% Summer total reserve margin criterion for 2022, even after the retirement of these 1,618 MW of Manatee generating capacity, with only 350 MW of replacement capacity needing to be added by the Summer of 2022. Second, the sooner the existing Manatee units can be retired, the sooner savings can be realized for customers by eliminating the approximately $36 million of average annual capital and O&M expenditures.

Q. Were there any other considerations that had to be accounted for when considering this early retirement and potential options for supplying replacement capacity?

A. Yes. Initial consideration of the retirement of the two existing Manatee units showed that, from a transmission planning and operational perspective, there was the potential of being unable to meet Winter peak load in the Manatee area without the two Manatee units if the early morning electrical load was particularly high. Thus, any consideration of options to replace the capacity that would be removed with the retirement of the existing Manatee units would need to include a resource(s) that could address this concern on Winter peak mornings. The magnitude of resources needed in/near the Manatee area on cold Winter mornings, before the selection of any resource additions, was projected at approximately 700 MW, and the projected duration of the concern was approximately 2 hours.

Q. What options were considered as potential replacements for the capacity that would be removed with the retirement of Manatee Units 1 & 2?

A. The generation resource options that were considered included: new gas-fueled generation, upgrades to the combustion turbine components of existing CC units, new solar, and battery storage. In addition, transmission projects in/near the Manatee area to help address the Winter early morning concern were also considered. Transmission options included acceleration of projects in/near the Manatee area that were already planned for later years or otherwise had been considered. With these transmission project accelerations, the magnitude of the Winter morning concern would be reduced from approximately 700 MW to 400 MW.

Each of the previously mentioned generation options, except for solar, could address both the Summer total reserve margin criterion and the Winter early morning concern. Because the Winter concern is for the early morning hours when the sun is below/at the horizon, solar could not directly assist in meeting this concern.

Consideration of these generation and transmission options led to an analysis that included a combination of many of these options including: acceleration of specific planned transmission projects from 2028 to 2021 and from 2028 to 2025; a nominal 400 MW 2.2 hour battery storage facility at the Manatee site; new and/or accelerated solar; new and/or accelerated CC units; and upgrades to the CT components of existing CC units. The first two types of options, acceleration of planned transmission projects and a Manatee battery storage facility, specifically addressed the Winter early morning concern. In addition, the battery storage facility, acceleration of CC units, and CT upgrades could also address the Summer total reserve margin criterion.

Q. Please discuss the analysis approach used in, and results of, the examination of the early retirement of the existing Manatee units and the addition of the Manatee battery project?

A. The analysis approach was a comparison of two resource plans that are presented in Exhibit SRS-3. In one resource plan, the retirement of the existing Manatee Units 1 & 2, plus the addition of 469 MW of battery storage (consisting of 409 MW at the Manatee site and 60 MW elsewhere in the FPL system), are assumed to have occurred by the beginning of 2022. This plan is labeled as the "Resource Plan w/ 2022 Manatee Changes" and it is identical to the plan presented in FPL's 2019 TYSP filing. In the other resource plan, the Manatee Unit retirements and the addition of 469 MW of battery storage was assumed to occur by the beginning of 2029. This second plan is labeled as the "Resource Plan w/ 2029 Manatee Changes".

A comparison of the two plans, using the Resource Plan w/ 2029 Manatee Changes as the starting point for the comparison, shows the following differences in the Resource Plan w/ 2022 Manatee Changes: (i) Manatee Units 1 & 2 are retired by 2022 instead of by 2029, (ii) the 469 MW of battery storage is added by 2022 instead of by 2029, (iii) 1,043 MW of solar are accelerated from 2026 to 2025, and (iv) a CC unit is accelerated from 2029 to 2026.

Q. What were the projected costs for the two resource plans?

A. The projected CPVRR costs for the two plans are also presented in Exhibit SRS-3. The projected CPVRR costs for the two resource plans are: $59,580 million for the Resource Plan w/ 2022 Manatee Changes, and $59,682 million for the Resource Plan w/ 2029 Manatee changes. Thus, the 2022 Manatee changes were projected to save FPL's customers approximately $101 million CPVRR compared to delaying these same Manatee changes to 2029.

Q. Were the annual O&M cost savings from the early retirement of the existing Manatee units, and the additional transmission costs from accelerating transmission projects in/near the Manatee area, included in the cost projections for the two resource plans?

A. Yes. The cumulative O&M cost savings from retiring Manatee Units 1 & 2 by 2022 instead of by 2029 were projected to be $258 million CPVRR. This was accounted for in the analysis by including these additional O&M costs in the CPVRR costs for the Resource Plan w/ 2029 Manatee Changes. In regard to the costs for the planned transmission projects in/near the Manatee area, the projected costs were accounted for in each resource plan. The projected CPVRR costs were $50 million for the Resource Plan w/ 2029 Manatee Changes (in which the original planned in-service dates for the transmission projects were assumed) and $63 million for the Resource Plan w/ 2022 Manatee Changes (which assumed the accelerated schedule for the projects). These costs were included in the costs for each respective resource plan. Therefore, the projected net incremental CPVRR cost of the accelerated transmission projects in/near the Manatee area was $13 (= 63 - 50) million.

Q. Please summarize your view of the Manatee modernization project.

A. Based on the economic analyses just discussed, the Manatee modernization project is estimated to result in significant economic savings for FPL's customers of $101 million CPVRR. In addition, the battery storage component of the project will provide FPL the opportunity to add to the knowledge FPL has already gained regarding battery construction, operation, and integration from prior and ongoing battery pilot projects. Therefore, I believe the Manatee modernization project will greatly benefit customers.

IV. OVERVIEW OF THE THREE-STEP APPROACH USED TO PERFORM RESOURCE PLANNING ANALYSES OF THE GULF AND FPL SYSTEMS

Q. What were Gulf and FPL seeking to determine when this analysis approach was designed?

A. Simply put, the analysis approach was designed to enable Gulf and FPL to answer the following three questions:

1) Are there changes/additions that can be made in the near-term (2020 through 2024) to Gulf's system of generation units that are projected to benefit Gulf's customers and could be completed relatively quickly?

2) Would increasing the transmission linkage between Gulf and FPL, that currently exists only through other utilities' transmission systems, via the NFRC be expected to result in additional benefits for Gulf's customers?

3) Would integrating the Gulf and FPL systems into a single utility system be projected to provide additional benefits to Gulf and FPL customers from a resource planning perspective?

Q. Please briefly explain the analysis approach.

A. The analysis approach consisted of three steps which can be summarized as follows:

<u>Step 1</u>: The focus is solely on the Gulf system. The assumption is that Gulf no longer has a commitment from Southern Company for firm electrical support and that no new transmission linkage to the FPL system will be added. The objective of Step 1 is to determine what generation system improvements can be made to the Gulf stand-alone system to benefit Gulf's customers. An optimized resource plan was developed for this stand-alone Gulf system, and a CPVRR cost for the resource plan was calculated. This resource plan and its associated CPVRR cost also serves as the appropriate starting point from which to evaluate the economics of the NFRC in Step 2.

Step 2: The focus is still primarily on the Gulf system (although the FPL system is also accounted for in this analysis step). The NFRC is assumed to be in-service by a certain date (which was initially projected to be January 1, 2022). The NFRC will result in a direct and enhanced electrical connection between the Gulf system and the FPL system, but both systems are assumed to remain separate utility systems. The objective of the Step 2 analysis is to determine if the economic benefits of the NFRC, particularly to Gulf's customers, were projected to be greater than the projected cost of the NFRC.

An optimized resource plan is first developed for FPL as a stand-alone system. This FPL resource plan ensures adequate capacity to meet a 20% total reserve margin for FPL's stand-alone system. Then, after FPL customers' energy needs are served, this resource plan also allows the AURORA model to determine the amount and marginal costs of available energy that could be transferred to Gulf from FPL as a result of the NFRC. Then, assuming that Gulf now has access to FPL's generation system via the NFRC, a new re-optimized resource plan for Gulf is developed. This Gulf resource plan is different than the resource plan developed in Step 1. The cost for this re-optimized resource plan, the cost of the energy that is transferred as a result of the NFRC, and the cost for the NFRC, are calculated and summed to develop a CPVRR total cost for Step 2.

The difference between the CPVRR cost for the initial Gulf resource plan from Step 1, and the CPVRR total cost from Step 2, is then calculated. The difference between these two costs represents the anticipated net CPVRR cost savings (if any) from the NFRC if Gulf and FPL were to remain as separate utility systems. The re-optimized resource plan for Gulf, the resource plan for FPL, and their associated CPVRR costs also represent the appropriate starting point from which to evaluate the economics of integrating the Gulf and FPL systems into a single utility system in Step 3.

Step 3: The objective is to evaluate the economics of combining the Gulf and FPL systems into a single integrated utility system in 2022, which is made possible by the NFRC. A new optimized resource plan for the integrated system is developed, and the CPVRR cost of the new plan is developed. The difference between this new CPVRR cost for Step 3 and the CPVRR total cost for the Gulf and FPL stand-alone systems from Step 2 represents the additional cost or cost savings from integrating the two utility systems.

Q. Are the resource plans in any of the three analysis steps identical to the resource plan that will be presented in the FPL/Gulf 2021 TYSP?

A. Yes. The resource plan for the integrated Gulf and FPL system that will be presented in the 2021 TYSP was the result of the current Step 3 analysis that will be discussed later in Section VII of my testimony.[15]

Q. What resource options were evaluated in the three-step analyses?

A. The following types of resource options were evaluated over the course of the three-step analysis process: universal solar, battery storage, new CC units, new

[15] This resource plan is also identical to the "With Programs" resource plan previously discussed in regard to the CDR/CILC incentive level analyses.

combustion turbines, capacity upgrades to existing units, coal-to-gas conversions of existing units, and unit retirements. In addition, all of the analyses assumed that the DSM Goals that the FPSC approved in its most recent DSM Goals proceeding for both Gulf and FPL will be achieved.

Q. What computer model was utilized in these analyses?

A. The AURORA optimization and production costing software was the primary model used in these analyses. FPL's resource planning group began using the AURORA model in the second half of 2018 after the acquisition of Gulf by FPL's parent company, NextEra Energy, had been announced. The AURORA model was obtained after determining that the optimization model previously used by FPL's resource planning group (EPRI's EGEAS model) could not simultaneously optimize two utility systems, or two areas of a utility system, with distinct limits on transmission flows between the areas.

The AURORA model has that needed capability. Consequently, FPL's resource planning group began testing the model in the second half of 2018 and early 2019 by running analyses with AURORA in parallel with analyses using EGEAS. An analysis period that ended in 2048 was utilized in these initial analyses. Based on successful testing, FPL began using the AURORA model for its resource planning work during the rest of 2019 and is currently using it with an analysis period that ends in 2068. The analysis work that supported the FPL/Gulf 2020 and 2021 TYSPs was performed using the AURORA model.

Q. Please explain why the initial analyses used an analysis period that ends in 2048 and subsequent analyses use an analysis period that ends in 2068.

A. There are two reasons for the use of the different analysis periods. First, when the initial analyses were being performed in early 2019, the only load forecast for Gulf that FPL had access to was a forecast from Southern Company that only went through the year 2043.[16] Second, as mentioned above, FPL was testing the AURORA model versus the EGEAS model during much of the initial analysis period. The EGEAS model's approach is to perform optimization analysis for a 30-year period (*i.e.*, from 2019 through 2048 in FPL's analysis), then essentially trend those results over additional years if a longer analysis period is desired. AURORA's approach is to perform actual optimization analyses over all years in the selected analysis period.

Therefore, in order to perform initial Step 1 and Step 2 analyses of the Gulf system, and test the optimization approach of the two models, the decision was made to perform analyses over a 30-year analysis period of 2019 through 2048. FPL's load forecasting team then extended the Gulf load forecast for the years 2044 through 2048 for purposes of these initial analyses and model testing. Current analyses utilize the AURORA model's capability to perform optimization analyses over a longer period and thus use a load forecast and an analysis period through 2068.

[16] This Gulf load forecast was the one used in Gulf's 2019 TYSP.

Q. In your testimony summary, you mentioned that analyses using the three-step approach began in the second half of 2018 and continue to the present. Are the results from the initial analyses directly comparable to the results from the current analyses?

A. No. From the second half of 2018 to the present, a number of key forecasts (electrical load, fuel costs, etc.) and assumptions (cost of capital, discount rates, costs of resource options, etc.) have changed at least once. In addition, as just discussed, the initial analyses accounted for costs for an analysis period consisting of the years 2019 through 2048 and the more recent analyses accounted for costs for an analysis period consisting of the years 2020 through 2068.

For these reasons, the CPVRR cost values for the resource plans that were developed in the initial analyses should not be numerically compared to the CPVRR cost values for the resource plans from the current analyses.

Q. With that in mind, how does your testimony present the results of the analyses that were performed?

A. My testimony separately presents the results of analyses of two vintages. First, the results of the initial analyses are presented in the next section (Section V) of my testimony. These analyses were performed in the time period spanning approximately mid-2018 through the first Quarter of 2019. These analyses are presented because they helped inform Gulf's decision-making regarding near-term changes/additions to its generation system. Using these analyses, Gulf decided to proceed with several of those changes/additions. As previously mentioned, some of those projects have been completed, and the rest are underway with a projected completion by year-end 2021. In addition, one of the results from the initial analyses was that the NFRC was projected to be economically beneficial for Gulf's customers based on then current forecasts and assumptions. This result prompted further analyses of both the NFRC line and the potential integration of the Gulf and FPL systems as forecasts and assumptions were updated.

The second set of results presented in my testimony are from the current analyses that were performed in the remainder of 2020/early 2021. The results from these analyses are presented in Sections VI and VII of my testimony and they provide the most up-to-date look at the economics of the NFRC and of the planned integration of the two utility systems. As such, the projected CPVRR values from the current analyses supercede/replace the CPVRR values from the initial analyses.

Q. In regard to the current analyses, what financial assumptions were used in those analyses?

A. The financial assumptions used in the current analyses are listed below:

- <u>for the Gulf stand-alone system in analysis Steps 1 & 2</u>: the currently authorized incremental capital structure of 46.50% debt and 53.50% equity, an 4.22% incremental cost of debt, the currently authorized 10.25% return on equity, and an after-tax discount rate of 6.95%. (Gulf's then current discount rate of 7.25% was used in the initial Step 1 and Step 2 analyses.)

- for both the FPL stand-alone system in analysis Step 2 and the single integrated system in analysis Step 3: an incremental capital structure of 40.40% debt and 59.60% equity, an incremental 4.10% cost of debt, the currently authorized 10.55% return on equity, and an after-tax discount rate of 7.52%. FPL witness Barrett discusses the capital structure further in his direct testimony.

Q. What load forecasts were used in the current set of analyses?

A. Those are the same load forecasts for Gulf and FPL that will be presented in the 2021 FPL/Gulf TYSP. Those load forecasts are presented in Exhibit SRS-4 on three pages. Page 1 of the exhibit presents forecasted Summer peak loads, page 2 presents forecasted Winter peak loads, and page 3 presents the forecasted net energy for load ("NEL"). These forecasts are described in greater detail in the testimony of FPL witness Park.

Q. What fuel cost forecasts were used in the current set of analyses?

A. Those forecasts are the same long-term fuel cost forecasts that were used to develop the 2021 FPL/Gulf TYSP. The fuel cost forecasts are presented in Exhibit SRS-5. These forecasts are also discussed in the testimony of FPL witness Forrest.

Q. What carbon dioxide ("CO_2") compliance cost forecast was used in the current set of analyses?

A. That forecast is the same compliance cost forecast for CO_2 from the consultant ICF that was used in the analyses that developed the 2020 FPL/Gulf TYSP and which were used to develop the 2021 FPL/Gulf TYSP filing. That forecast is presented in Exhibit SRS-6.

V. RESULTS OF INITIAL ANALYSES W/ FOCUS ON NEAR-TERM CHANGES/ADDITIONS FOR THE GULF GENERATION SYSTEM

Q. In the initial analyses, which steps in the three-step analytical approach were most important?

A. In the initial analyses, Steps 1 and 2 were the most important for a couple of reasons. First, Gulf wanted to see if there were system improvements (*i.e.*, changes/additions) that could be made to its generation system that would benefit its customers and might be completed relatively quickly. Second, only after identifying cost-effective changes/additions to Gulf's generation system with Gulf as a stand-alone utility, could a meaningful first look be taken at the economics of the NFRC (which, in turn, would be crucial to any later examination of the economics of potentially integrating the Gulf and FPL systems). For these reasons, this section of my testimony will focus on the results from the initial Step 1 and Step 2 analyses.

Q. Because Gulf was being evaluated in the Step 1 analyses as a stand-alone utility system, at least one reliability criterion had to be developed with which to analyze and plan the Gulf system. What reliability criterion was used in the analyses, and what was the rationale for that criterion?

A. A Summer and Winter minimum total reserve margin criterion of 30% was selected as a reliability criterion for the Gulf stand-alone system in the Step 1 analysis. When viewed as a separate system, and not as part of the much larger Southern Company system, Gulf can be characterized as a relatively small system with several very large generation resources as shown below in Table SRS-3.

Table SRS-3
Gulf Power Generating Units

Resource	Unit No.	Type of Unit/Fuel	Firm MW Summer	Unit or PPA	% of Total MW
Crist	4	Coal	75	Unit	2%
Crist	5	Coal	75	Unit	2%
Crist	6	Coal	299	Unit	9%
Crist	7	Coal	475	Unit	15%
Daniel	1	Coal	251	Unit	8%
Daniel	2	Coal	251	Unit	8%
Lansing Smith	3	CC	577	Unit	18%
Lansing Smith	A	CT	32	Unit	1%
Pea Ridge	1	CT	4	Unit	0%
Pea Ridge	2	CT	4	Unit	0%
Pea Ridge	3	CT	4	Unit	0%
Perdido	1	LFG	1.5	Unit	0%
Perdido	2	LFG	1.5	Unit	0%
Scherer	3	Coal	215	Unit	7%
Kingfisher	I & II	Wind	89	PPA	3%
Gulf Coast Solar	I, II, & III	Solar	34	PPA	1%
SENA (Shell)	---	CC	885	PPA	27%
		Total =	**3,273**		**100%**

Source: Gulf 2019 TYSP

As shown in the shaded rows of this table, Gulf's three largest generation resources are the Shell Power Purchase Agreement ("PPA") of 885 MW, the Lansing Smith Unit 3 with 577 MW, and the Crist Unit 7 with 475 MW. As also shown in these shaded rows, these three generation sources represent the following percentages of Gulf's total generation capability: 27% (Shell PPA), 18% (Lansing Smith Unit 3), and 15% (Crist Unit 7). In total, fully 60% of Gulf's total generation capability is provided by just these three generation resources. In addition, Gulf has a relatively small number of generation resources: 20.

By comparison, as shown in the FPL/Gulf 2020 TYSP, FPL's largest generation resource is its Ft. Myers Unit 2 with a Summer capability of 1,812 MW which represents less than 7% of FPL's total firm generation capacity of 26,585 MW. In terms of the total number of generation resources, FPL had 56 generation resources at the end of 2019. Thus, Gulf as a stand-alone system has a generation profile that is significantly different than FPL's profile: Gulf has many less generation resources, and several of these resources are very large in comparison to the total generation capability.

When selecting a reserve margin criterion, one of the typical considerations is whether the utility's reserve margin is large enough to allow the utility to still serve its customers if the largest generation resource on the system is unexpectedly lost. Because the Shell PPA represents 27% of Gulf's total generation, this consideration suggests that the total reserve margin criterion for a Gulf stand-alone system should be at least 27%.[17] This consideration, when combined with other considerations such as: (i) Gulf has two other very large (relative to Gulf's total generation capability) generation resources, (ii) a relatively small total number of generation resources, (iii) very little fast start/fast ramping capability, and (iv) no significant load management/load control capability, led to the conclusion that a reserve margin criterion in excess of 27% is warranted. For these reasons, a total reserve margin criterion of 30% was assumed in these analyses for a stand-alone Gulf system without any significant new firm transmission ties to other utilities.

Q. What were the results of these initial Step 1 analyses?

A. The results of the initial Step 1 analyses are summarized on page 1 of 2 of Exhibit SRS-7. This page presents 8 different cases or analyses that were performed. These were labeled as the Base Case and Cases 1 through 7. At the top of the page is a matrix that shows (marked with an "X") what resource options were assumed to be eligible in each case for consideration by the AURORA optimization model.

The basic approach was to determine the optimized resource plan for each case using the resource options that were eligible for that case. Then, one more eligible resource option at a time is added for the next case, re-optimizing the

[17] The Shell PPA will terminate in May 2023. At the time the initial analyses were performed, an extension of the PPA was considered potentially feasible. However, the CC unit which is the generation source for the PPA was subsequently purchased by Alabama Power for its own use.

plan each time. For each case, the projected CPVRR cost for the years 2019 through 2048 was developed and compared to the prior case to determine what the CPVRR savings (if any) might be from the new case. For example, in the Base Case, only new CT and new CC options were allowed. This case was analyzed first because Gulf's 2019 TYSP had showed only natural gas-fueled options being added to the Gulf system. Starting with a Base Case in which only gas-fueled resource options could be selected was an effort to start with a resource plan that was reasonably similar to what was shown in Gulf's 2019 TYSP; *i.e.*, a type of "business as usual" case.

For the Base Case, the AURORA model selected a total of 4 CTs of 235 MW each. The projected CPVRR cost for the Base Case was $7,887 million. Then Case 1 introduced as an additional eligible option the early (2024) retirement of Gulf's 50% ownership portion (equaling 502 MW) of the Daniel Units 1 & 2. The resulting re-optimized resource plan for Case 1 did select the early retirement of the Daniel coal units, plus added a new CC and deferred one of the CTs as shown in the exhibit. The projected CPVRR cost for the Case 1 resource plan was $7,658 million which results in a projected CPVRR cost savings of $229 (= 7,887 – 7,658) million compared to the Base Case. This add-one-more-option-at-a-time, then-re-optimize process continued for the remaining 6 cases.

The last column on page 1 of 2 of this exhibit presents the optimized resource plan for Case 7 in which all resource options were made available to the AURORA model. As shown by a comparison of resource additions in the last column versus the resource additions in the Base Case column, a number of changes/additions were projected to be cost-effective for Gulf's customers. In these initial analyses, the projected total CPVRR savings for Case 7, compared to the Base Case, was $691 million. The resource plan shown as Case 7 represented the optimized resource plan from the initial analyses for Gulf as a stand-alone system assuming no additional firm transmission linkage to FPL's system.

Q. In regard to the initial Step 2 analysis that followed, and which did assume additional firm transmission linkage to FPL via the NFRC, were there any changes in basic assumptions at the start of the initial Step 2 analyses?

A. Yes. There were two changes in basic assumptions for Step 2. First, the early retirement of the Daniel coal units in 2024, which was projected to be cost-effective in the Step 1 analysis, was assumed as a "given" going into Step 2.[18] Second, when assuming that Gulf would have access of up to 850 MW of transfer capability from FPL due to the NFRC, the decision was made to reduce Gulf's total reserve margin criterion from 30% to 20% once the NFRC is in-service.

[18] In early January of 2019, Gulf informed Mississippi Power (the other co-owner of the Daniel coal units) of Gulf's intent to terminate Gulf's ownership portion of the Daniel units in January 2024.

Q. Please discuss the decision to reduce Gulf's reserve margin criterion to 20% in the initial Step 2 analyses.

A. Compared with the position of a stand-alone Gulf system with no additional transmission linkage to FPL, and assuming all else equal, the Gulf system will be more reliable once the NFRC is completed. With the completion of the NFRC, Gulf will have a very large firm transfer capability around the clock from FPL's much larger system of generating units. Because the Gulf system will be more reliable with the NFRC in place, a lower reserve margin criterion can be used to plan for a stand-alone, but enhanced electrically connected, Gulf system. Knowing that the later Step 3 analyses would be evaluating the economics of a single integrated system with a single reserve margin criterion, and that FPL's total reserve margin criterion is 20%, the decision was made to lower Gulf's reserve margin criterion to 20% in the Step 2 analyses.

Q. What were the results of the initial Step 2 analyses?

A. The results of those analyses are presented on page 2 of 2 in Exhibit SRS-7. The addition of the NFRC was assumed at that time to allow Gulf to have access of up to 850 MW per hour of energy from FPL's more efficient generating system.[19] As a result, a re-optimized resource plan for Gulf was selected by the AURORA model. As shown on this page of the exhibit, this new resource plan was projected to result in additional net benefits to Gulf's customers of $194 million CPVRR when compared to the Case 7 resource plan from Step 1. These projected additional net benefits account for both the then-projected capital

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[19] During 2019, Gulf's system of fossil fueled generating units had a system average heat rate of approximately 9,000 BTU/kWh. FPL's system average heat rate was approximately 7,000 BTU/kWh.

cost, and fixed operating and maintenance costs, of the NFRC line as well as the projected cost of reimbursing FPL for the cost of energy delivered to Gulf.

Q. Based on these initial Step 1 and Step 2 results, did Gulf decide to proceed with any of the near-term generation changes/additions?

A. Yes. The decision was made to proceed with several changes/additions to Gulf's generation system that were projected to be cost-effective in the initial Steps 1 and 2 analyses (*i.e.*, these changes/additions were projected to be cost-effective both with and without the NFRC). These changes/additions were (in no particular order):

- the upgrade of the Lansing Smith CC unit (approximately 80 MW);
- the conversion from coal-fueled to gas-fueled of the Crist Units 6 & 7;
- the addition of three 75 MW solar facilities; and,
- the addition of 4 new CT units.

Q. In regard to the 4 new CT units, was there a subsequent decision to change the in-service date(s) of these units and, if so, why?

A. Yes, there was a decision to advance the in-service dates of the 4 CTs that each provide approximately 235 MW of capacity. In these initial Step 2 analyses, the AURORA model selected two CTs in 2023 and two more CTs in 2024 as shown in Exhibit SRS-7, page 2 of 2. After discussions with FPL's System Operations and Transmission Planning departments, the decision was made to accelerate all 4 CTs so that they were in-service by the end of 2021/start of 2022 which was the then earliest projected in-service date for the NFRC line. This change to the in-service dates of the CTs was made to provide fast-start/fast ramp capability for the Gulf system that would be needed in case of the unexpected loss of either the transfer capability provided by the NFRC and/or the upgraded (approximately 80 MW larger) Lansing Smith CC unit. The decision was also made to site these 4 CTs at the Crist plant site. The projected CPVRR cost of this CT acceleration was approximately $60 million which was accounted for in all subsequent analyses.

Q. In regard to the NFRC, did the results of the initial Step 2 analyses support further analysis of, and preparation for, the NFRC?

A. Yes. The projected CPVRR net savings of $194 million for Gulf customers from connecting Gulf and FPL via the NFRC definitely supported further analysis of this option.

VI. RESULTS OF THE CURRENT ANALYSES W/ FOCUS ON CONNECTING THE GULF AND FPL SYSTEMS WITH THE NORTH FLORIDA RESILIENCY CONNECTION

Q. In the current analyses, were all three steps of the analysis approach performed, and did the analyses use updated forecasts and assumptions?

A. The answer to both questions is "yes". Because a decision had been made to implement a number of near-term changes/additions to Gulf's generation system that had been identified as cost-effective in the initial Steps 1 and 2 analyses, subsequent analyses from that time to the present have had as their primary focus the updating of the Step 2 analysis (to refine the view of the economics regarding the NFRC) and performing the Step 3 analysis (to determine the economics of integrating the Gulf and FPL systems). However, in order to develop an updated view of the projected economics of the NFRC, it was necessary to perform updated Step 1 analyses. The updated Step 1 analyses are needed in order to determine what the optimized resource plan for a stand-alone Gulf system would be using updated forecasts and assumptions after accounting for the previously discussed decision to proceed with several changes/additions to Gulf's system. These updated forecasts and assumptions were also used in the current Step 2 and Step 3 analyses.

Q. What were the results of the current Step 1 analysis?

A. Those results are presented in Exhibit SRS-8 which presents the results for two analysis cases. Case 1a in that exhibit assumed that the following changes/additions are a "given" in the analyses: Lansing Smith upgrade, coal-to-gas conversion of the Crist Units 6 & 7, new solar, and 4 CTs at the Crist site. In addition, Case 1a assumed that new CTs and CCs were the only eligible resource options; *i.e.*, a "business as usual" case (that is analogous to the Base Case previously discussed in regard to the initial Step 1 analyses). The AURORA model then developed a new optimized resource plan for this Case 1a in which one other resource in the 2020 through 2030 time period was selected in order to meet the reserve margin criterion. That resource addition was the Escambia CC unit in 2030. The projected CPVRR cost (for the years 2020 through 2068) for the Case 1a resource plan is $10,199 million.

Case 1b assumed the same “given” generation changes/additions and used an expanded list of other eligible resource options that includes: CTs, CCs, early (2024) retirement of Gulf’s ownership portion of Daniel Units 1 & 2, solar, and storage. All of these resource options were assumed to be eligible for selection in Case 1b analysis (and this case is analogous to Case 7 previously discussed in regard to the initial Step 1 analyses). The optimized resource plan selected in Case 1b consisted of: the early Daniel retirement, approximately 373 MW of solar, and 100 MW of storage. In addition, the Escambia CC unit was advanced three years to 2027. The projected CPVRR cost for the resource plan for Case 1b is $9,342 million which is $856 (= 10,199 – 9,342) million CPVRR lower than the projected cost for Case 1a. The projected CPVRR savings are also presented below in Table SRS-4.

Table SRS-4
Summary of Results from the Current Steps 1 through 3 Resource Planning Analyses

Analysis Step	Focus of Analysis Step	Projected Net Savings (CPVRR, millions)	Projected Cumulative Net Savings (CPVRR, millions)	Comments
Step 1	Value of near-term improvements (changes/additions) to Gulf's system of generation units	856	856	The value shown does not account for the projected savings for several changes/additions to Gulf's generation system that were selected based on the initial analyses and which are either already in place or are in progress.

Note: CPVRR net savings projections shown in the 3rd and 4th columns are for the years 2020 through 2068

As indicated in the Comments column of Table SRS-4, the projected CPVRR savings amount of $856 million does not account for the projected savings from the Lansing Smith upgrade, the Crist coal-to-gas conversion of Units 6 and 7, the 4 CTs at Crist, and early solar because these previously decided upon generation changes/additions are included in the resource plans for both Cases 1a and 1b.

Q. In regard to the current Step 2 analyses, were there any changes from the initial Step 2 analysis in regard to the NFRC line itself?

A. Yes. There were three such changes. First, the projected in-service date for the NFRC line moved slightly from the January 1, 2022 in-service date assumed in the initial Step 2 analyses to June 30, 2022. Second, transmission load flow studies had been performed since the initial analyses were completed. Based on the results of these studies, the projected transfer capability resulting from the NFRC has changed from an assumed 850 MW for all hours and years to annual average hourly values of approximately 624 MW for the years 2022 through 2025, then to approximately 827 MW for all years from 2026-on.[20] Third, the forecasted cost for the NFRC expanded to account for all currently known cost components of the NFRC.

Q. Please describe in more detail what is meant by the "NFRC".

A. Due to the interconnected nature of the bulk electric system, and with the new transmission line component of the NFRC in place, energy is projected to flow between FPL and Gulf not only over the new line, but also over existing transmission lines owned by other utility systems, particularly the Southern

[20] The current projection is that the originally assumed 850 MW transfer capability will still be possible for many hours of each year, but that there will be transfer limitations during some higher load hours. The annual average hourly transfer value described above is merely a "shorthand" way to reflect those limitations.

Company system. Consequently, the transfers of energy between FPL and Gulf enabled by the NFRC are made possible not only by the new transmission line component of the NFRC, but also by system improvements made to the Southern Company transmission system that are needed as a result of the increased flow on their lines.[21] In addition, a PPA for the Winter months is needed for a few years to address potential limitations in the capability to transfer power from FPL to Gulf that could arise during higher than normal forecasted Winter load levels in the Gulf area.

As a result, the current total projected cost of the NFRC encompasses four cost components. These components are: (i) the capital cost of the new transmission line, (ii) the annual O&M costs associated with the new line, (iii) capital expenditures paid to the Southern Company for improvements on its transmission system needed due to the increased energy flow between FPL and Gulf, and (iv) a projected short-term PPA using representative pricing that is needed to address potential high load scenarios in the Winter months for a few years after the NFRC goes in-service.[22] The projected costs for these components are presented later in my testimony.

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[21] At the time this testimony is filed, transmission flow studies involving the Duke Energy Florida ("DEF") transmission system were still on-going. Consequently, potential impacts to the DEF system have not yet been conclusively determined.

[22] In the initial Step 2 analyses, only the then-current projections for cost components (i) and (ii) were accounted for. Cost components (iii) and (iv) were determined later after the conclusion of multi-party transmission studies which had not been completed at the time the initial Step 2 analyses were performed.

Q. What were the results of the current Step 2 analysis that accounted for all of the costs of the NFRC components as well as for updated forecasts and assumptions?

A. Those results are presented in Exhibit SRS-9. As shown in this exhibit, the projected CPVRR cost for the optimized resource plan for Gulf in the current Step 2 analysis is $8,953 million. When compared to the projected CPVRR cost of $9,342 million for the optimized resource plan for the stand-alone Gulf system from Step 1, the projected net CPVRR savings for the NFRC is $389 (= 9,342 – 8,953) million. This projected savings value represents additional savings for Gulf's customers as shown below in Table SRS-5.

Table SRS-5
Summary of Results from the Current Steps 1 through 3 Resource Planning Analyses

Analysis Step	Focus of Analysis Step	Projected Net Savings (CPVRR, millions)	Projected Cumulative Net Savings (CPVRR, millions)	Comments
Step 1	Value of near-term improvements (changes/additions) to Gulf's system of generation units	856	856	The value shown does not account for the projected savings for several changes/additions to Gulf's generation system that were selected based on the initial analyses and which are either already in place or are in progress.
Step 2	Additional value of connecting Gulf and FPL via the NFRC	389	1,245	Net savings value accounts for the projected costs of the NFRC.

Note: CPVRR net savings projections shown in the 3rd and 4th columns are for the years 2020 through 2068

Q. Exhibit SRS-9 shows the projected CVPRR total cost for the NFRC is $722 million. Please explain that total cost and whether FPL compared that projected cost of the NFRC to the projected costs of wheeling the same amount of hourly energy through either the Southern or DEF transmission systems.

A. Both of these items are addressed in Exhibit SRS-10. Page 1 of 4 of this exhibit shows a summary of the projected CPVRR costs of the NFRC, and the projected costs of wheeling on a firm point-to-point basis an amount of hourly energy that matches the projected average annual transfer capability of the NFRC (624 MW for 2022 through 2025, then 827 MW thereafter). Page 1 shows that the CPVRR cost of the NFRC is projected to be at least $560 million lower than the lowest CPVRR cost of wheeling through either of these two transmission systems. Stated another way, the estimated CPVRR cost of the NFRC, $722 million, is only 56% of the estimated lowest CPVRR cost, $1,282 million, of wheeling the same amount of capacity and energy through existing transmission lines of other utilities.

Page 2 of 4 of Exhibit SRS-10 presents the projected annual revenue requirements for the capital cost of the NFRC line and for the other cost components of the NFRC. In his testimony, FPL witness Spoor discusses the projected installed cost of the NFRC line that is used as an input in the calculation of the NFRC's CPVRR capital cost. Then Pages 3 of 4 and 4 of 4, respectively, present the projected costs for wheeling energy through Southern Company's transmission system and through DEF's transmission system.

Q. Because the bi-directional NFRC line allows a flow of energy from FPL to Gulf, and from Gulf to FPL, how was the cost of the NFRC "allocated" between Gulf and FPL for purposes of the Step 2 analyses?

A. In the Step 2 analyses, in which Gulf and FPL are assumed to remain separate utility systems, the total cost of the NFRC was allocated to Gulf. The rationale for this was that almost all of the benefits from the NFRC in the Step 2 analyses are projected to be received by Gulf's customers. Approximately 98% of the total flow of energy between the two utility systems is projected to be from FPL to Gulf which benefits Gulf's customers. The remaining approximately 2% of the flow is from Gulf to FPL which benefits FPL's customers.

Q. In Exhibit SRS-9, there is a CPVRR net cost of $2,186 million for the energy that is projected to flow from FPL to Gulf due to the NFRC. How was that projected cost developed?

A. A resource plan for a stand-alone FPL system was first developed using the AURORA model. That resource plan is presented in Exhibit SRS-11 along with its projected total CPVRR cost of $74,756 million. In developing that resource plan, the portion of that total CPVRR cost that is comprised of energy/variable costs was identified. Those projected energy/variable CPVRR costs were $60,768 million. This cost represents the energy/variable costs for meeting only FPL's forecasted load.

Then AURORA assumed the NFRC line was in place and developed the optimized Step 2 resource plan for Gulf. While developing the Step 2 plan for Gulf, AURORA kept the resource plan for the FPL stand-alone system presented in Exhibit SRS-11 unchanged, but allowed energy to flow over the NFRC line to/from Gulf as economics dictated. The projected CPVRR energy/variable costs for the FPL system from this run increased to $62,714 million. The difference in energy/variable costs between these two runs was $1,946 (= 62,714 – 60,768) million CPVRR using the FPL discount rate of 7.52%. After converting this value using Gulf's discount rate of 6.95%, the resulting cost is $2,186 million CPVRR. This value represents Gulf's cost of the net energy that flows from FPL to Gulf.

Q. Please explain how the costs for the energy transmitted by FPL and used by Gulf were accounted for in the analyses.

A. The cost of energy produced by the FPL system that is transmitted to Gulf via the NFRC are assumed to be recovered by FPL from Gulf area customers on a dollar-for-dollar basis. This treatment of those costs is appropriate because FPL and Gulf have already legally merged. On May 1, 2020, FPL and Gulf filed with the Federal Energy Regulatory Commission ("FERC") for approval to legally merge the two utilities under Section 203 of the Federal Power Act. This request was granted by FERC on October 15, 2020 and went into effect on January 1, 2021. As a result of Gulf's customers paying on a dollar-for-dollar cost basis for the marginal cost of energy being delivered from the FPL system to Gulf, no cost impact was projected for FPL's customers.

VII. RESULTS OF THE CURRENT ANALYSES W/ FOCUS ON INTEGRATING THE GULF AND FPL SYSTEMS INCLUDING PLANNED SOLAR ADDITIONS FOR 2022 THROUGH 2025

Q In the current Step 3 analyses that examines integrating Gulf and FPL into a single system, were there certain facets of this analysis that would be helpful to note?

A. Yes. There are four such items that are worth pointing out. These include: (i) how the cost for the NFRC line was handled, (ii) how the fact that the current Gulf and FPL utility systems have different discount rates was addressed, (iii) how the effect of the 20% total reserve margin criterion might change with an integrated system, and (iv) how the peak load to be served is affected by the integration of the two systems.

In regard to the first of these four items of note (how the cost for the NFRC line was handled), a Step 3 analysis is basically a comparison of the total costs for the Gulf system plus the FPL system from Step 2, and the cost for the integrated system in Step 3. Because the actual cost of the NFRC will be incurred in both Step 2 and Step 3, the cost of the NFRC was removed at this point to simplify the analyses.

Q. How was the second item of note (different discount rates for the two utilities) addressed in the Step 3 analyses?

A. In order to compare the remaining costs (the resource plan costs and the costs of the energy delivered by the current FPL system to the current Gulf system), it was first necessary to use a common discount rate. The FPL discount rate of 7.52% was used for this purpose. When replacing the 6.95% discount rate used in the current analyses for Gulf with this 7.52% discount rate, the projected CPVRR cost for just the Gulf resource plan changed from $6,046 million (shown in Exhibit SRS-9) to $5,527 million. In addition, the projected CPVRR cost for the FPL-to-Gulf delivered net energy changed from $2,186 million (also shown in Exhibit SRS-9) to $1,946 million (as previously mentioned). The sum of these two new CPVRR values is $7,474 (= 5,527 + 1,946) million. Then the projections of $7,474 million CPVRR cost for the Gulf system, and the $74,756 million CPVRR cost for the FPL system (shown in Exhibit SRS-11), were summed to derive a total combined CPVRR cost of $82,230 million. This revised-to-FPL's-discount-rate CPVRR cost value for the current Step 2 analyses was then compared to the projected CPVRR cost for Step 3 to determine the projected economic benefits (if any) from integrating the two utility systems from a resource planning perspective.

Q. Please briefly discuss the third item of note: how the effect of the 20% total reserve margin criterion might change with an integrated system.

A. In an integrated FPL/Gulf system, the minimum 20% total reserve margin criterion itself does not change; however, 20% reserves no longer have to be maintained separately in both Gulf's former service area and the rest of FPL's service area. A 20% reserves level only needs to be met overall for the integrated system. This raises the possibility that less total new generation may need to be built in the integrated system.

Q. The fourth item of note that you mentioned is how the peak load to be served is affected by the integration of the two systems. Please discuss.

A. This is demonstrated in the last three columns of the previously introduced Exhibit SRS-4, page 1 of 3. Column (3) on this page of the exhibit presents the forecasted load for the single integrated system. Then Column (4) presents the arithmetic sum of the Summer peak loads for FPL only and Gulf only.

Column (5) shows the difference between the Summer peak load for the single integrated system from Column (3) and the sum of the two peak loads in Column (4). As shown in Column (5), the coincident Summer peak load for the single integrated system is lower each year than the sum of the peak loads for the two stand-alone systems by approximately 136 MW to 215 MW.[23]

What this means from a resource planning perspective is that when planning the single integrated system, one has to plan for 136 MW to 215 MW less Summer peak load. Applying the 20% total reserve margin criterion to this load differential means that a total of approximately 163 MW (= 136 x 1.20) to 258

[23] A similar (and even larger) result occurs for Winter peak load through 2038 as shown in Exhibit SRS-3, page 2 of 3. No such change occurs for NEL as shown on page 3 of 3 of that same exhibit.

MW (= 215 x 1.20) fewer generation resources need to be added to the single integrated system than if the systems were not integrated.

Having to plan for a smaller amount of peak load will, all else equal, result in fewer new resources being added and lower fixed costs for the single integrated system.

Q. What were the results from the current Step 3 analyses?

A. The results of this analysis are presented in Exhibit SRS-12. As shown in this exhibit, the projected CPVRR cost of the resource plan for the single integrated system is $81,942 million. This value is compared to the previously discussed Step 2 total CPVRR cost for Gulf's resource plan (adjusted for FPL's discount rate), and for FPL's resource plan, of $82,230 million. This comparison shows that the integration of the two systems is projected to result in an additional $288 (= 82,230 – 81,942) million CPVRR savings. These additional savings are also presented below in Table SRS-6 (which is identical to Table SRS-Summary that was presented near the beginning of my testimony). This table also shows that the projected CPVRR total cost savings from the resources selected in the current Steps 1 through 3 analyses are $1,533 million or $1.5 billion.

Table SRS-6
Summary of Results from the Current Steps 1 through 3 Resource Planning Analyses

Analysis Step	Focus of Analysis Step	Projected Net Savings (CPVRR, millions)	Projected Cumulative Net Savings (CPVRR, millions)	Comments
Step 1	Value of near-term improvements (changes/additions) to Gulf's system of generation units	856	856	The value shown does not account for the projected savings for several changes/additions to Gulf's generation system that were selected based on the initial analyses and which are either already in place or are in progress.
Step 2	Additional value of connecting Gulf and FPL via the NFRC	389	1,245	Net savings value accounts for the projected costs of the NFRC.
Step 3	Additional value of integrating the Gulf and FPL systems into a single utility system	288	1,533	These additional savings are made possible by the addition of the NFRC. The NFRC is directly or indirectly responsible for a projected $677 million CPVRR savings (= 389 + 288).

Note: CPVRR net savings projections shown in the 3rd and 4th columns are for the years 2020 through 2068

Q. Would this additional $288 million CPVRR cost savings amount for customers have been possible without the transfer capability provided by the NFRC?

A. No. The NFRC allows the two systems to be economically combined into a single integrated system. Thus, the projected net savings from Steps 2 and 3 are either directly or indirectly due to the NFRC. As described in the Comments column on the last row of Table SRS-6 above, those projected net CPVRR benefits of the NFRC are the sum of the $389 million savings from the Step 2 analysis and the $288 million in additional savings from the Step 3 analysis, or a total of $677 million CPVRR.

Therefore, the NFRC is forecasted to be an even more cost-effective addition for customers than was projected in the Step 2 analyses alone.

Q. The resource plan from the current Step 3 analysis presented in Exhibit SRS-12 shows almost 3,000 MW of new solar facilities planned to be added in the years 2022 through 2025. Would you please comment, from a resource planning perspective, on these planned solar additions?

A. Yes. These planned solar additions are shown on the right-hand side of Exhibit SRS-12 for those four years in the two columns labeled, respectively, as FPL Area Resource Additions and Gulf Area Resource Additions. As indicated by this exhibit, these solar additions are part of the optimized resource plan developed in the current Step 3 analyses for the single integrated system which is projected to be $288 million less expensive than the sum of CPVRR costs for the Gulf and FPL stand-alone resource plans.

Table SRS-7 below provides a more detailed break out of these planned solar additions for the years 2022 through 2025 by geographic area (FPL or Gulf) and by solar technology type (fixed tilt or tracking).

Table SRS-7
2022 - 2025 Solar: By Location & Type
(Nameplate MW)

	(1)	(2)	(3)	(4)	(5) = (1) + (2)	(6) = (3) + (4)	(7) = (5) + (6)
Year	**FPL Area Solar Fixed**	**FPL Area Solar Tracking**	**Gulf Area Solar Fixed**	**Gulf Area Solar Tracking**	**FPL Area Total Solar**	**Gulf Area Total Solar**	**Integrated System Total Solar**
2022	372.5	74.5	0	0	447	0	447
2023	223.5	149	149	223.5	372.5	372.5	745
2024	0	521.5	372.5	0	521.5	372.5	894
2025	0	521.5	372.5	0	521.5	372.5	894
Totals =	**596.0**	**1,266.5**	**894**	**223.5**	**1,862.5**	**1,117.5**	**2,980.0**
Percentage of Total Solar Additions by Area =					**63%**	**38%**	
Tracking % of Total Solar Additions =					**50%**		

From a resource planning perspective, there are two interesting aspects regarding this table. The first interesting aspect is that although electrical load in Gulf's former service area is roughly only 10% of the load in the rest of FPL's service area, 38% (representing 1,117.5 MW) of the total planned new solar additions for these years is projected to be located in Gulf's former service area as shown at the bottom of Column (6). What is primarily driving this outcome is the integration of the two systems.

When the coincident Summer peak for the integrated system occurs at 4 to 5 p.m. (Eastern Daylight Time), the sun appears higher in the sky in the Gulf area than it appears in the FPL area because Gulf's area is west of FPL's area. Consequently, solar facilities sited in Gulf's area will – all else equal – have greater output at the time of Summer peak hour. Thus, solar facilities sited in

Gulf's former service area have a higher firm capacity value (*i.e.*, the percentage of a solar facility's nameplate rating that is assumed to be providing energy to the utility system at the peak hour). Thus, the AURORA model favors – all else equal – solar sited in Gulf rather than in FPL.

The second interesting aspect of this table is that 50% of the total planned solar additions for 2022 through 2025 are projected to be solar tracking facilities. All else equal, solar tracking facilities are currently projected generally to be more cost-effective than solar fixed tilt facilities. Currently there are a limited number of sites suitable for solar tracking facilities in both the FPL and Gulf areas given hurricane wind loading requirements. However, more suitable-for-tracking sites for solar additions in the 2022 – 2025 time period have now been identified than was the case when prior resource planning analyses were performed. As a result, more solar tracking facilities have been selected. FPL witness Valle addresses these and other solar siting issues in his testimony.

Q. What is the amount of firm capacity that is projected to be added in 2022 through 2025 in Gulf's former service area by the 1,117.5 MW of nameplate solar facilities?

A. As shown in Table SRS-7 above, the 1,117.5 MW of nameplate solar planned in Gulf's former service area in 2022 through 2025 are a mix of fixed tilt and tracking facilities. In combination, the projected firm capacity value of these 1,117.5 MW is approximately 47%. Thus, the associated firm capacity value of this Gulf area solar through 2025 is approximately 525 MW (= 1,117.5 x 0.47).

To help put this in perspective, this 525 MW of firm capacity projected to be supplied by solar additions in Gulf's former service area is greater than the 502 MW of firm capacity that is being removed from the former Gulf system with the retirement of Gulf's ownership portion of the Daniel coal units.

Q. Does the fact that almost 40% of the total planned solar MW additions in 2022 through 2025 will be sited in Gulf's former service area represent benefits for customers throughout FPL's service area?

A. Yes. Customers throughout the integrated utility's service area are projected to benefit from the ability to site new solar facilities in Gulf's former service area because these sites result in higher firm capacity values. The higher firm capacity values result in fewer new MW of new capacity that must be added overall, thus reducing fixed costs for new capacity.

Q. Regarding these planned solar facilities, FPL is asking for approval in this docket to recover costs for the solar facilities to be brought into service in 2022 and 2023. Please discuss the approach used to determine that these solar additions are cost-effective for customers.

A. In order to determine if the planned 2022 and 2023 solar additions are cost-effective, FPL utilized the same FPSC-accepted evaluation approach of comparing two resource plans used previously to analyze solar additions in FPL's 2017 through 2020 solar base rate adjustment ("SoBRA") filings. Both of these resource plans account for all solar facilities that have been previously installed, or are in the process of being installed, through 2021. The first resource plan, the "No Solar After 2021" plan, assumes no new solar will be added after 2021. The second resource plan, the "No Solar After 2022 & 2023 Solar Additions" plan, assumes the planned solar additions for the years 2022 and 2023 only, but no new solar after that.

The projected CPVRR costs for the two resource plans are developed and compared. If the CPVRR cost for the second resource plan with the 2022 and 2023 planned solar only is projected to be lower than the CPVRR cost of the "No Solar After 2021" plan, then the solar additions for 2022 and 2023, compared to no new solar additions, are projected to be cost-effective.

Q. What were the results of the comparison of these two resource plans?

A. The two resource plans described above, and their associated projected CPVRR costs, are presented in Exhibit SRS-13. The projected CPVRR costs are:

- The No Solar After 2021 plan: $67,087 million; and,
- The No Solar After 2022 & 2023 Solar Additions plan: $66,684 million.[24]

A comparison of the CPVRR costs for these plans shows that the 2022 and 2023 solar additions are projected to save $397 (= $68,116 - $67,718) million CPVRR. Thus, the planned solar additions for 2022 and 2023 are projected to be cost-effective for customers.[25]

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[24] The SoBRA approach that has been used by FPL to-date analyzes costs for solar projects assuming a 30-year book life for the solar facilities. This approach was again used for this analysis of the 2022 and 2023 planned solar additions and, accordingly, the CPVRR calculations address the years 2020 through 2053.

[25] Note that this analysis of the 2022 & 2023 solar facilities is unique because it is assumed that no additional solar would be built except in these two years. For this reason, these projected savings are not additive to the results of other analyses described previously in my testimony.

VIII. CONCLUSIONS

Q. Regarding FPL's requested increase in base rates in this docket, what conclusion do you draw from the analyses you have discussed in your testimony?

A. My testimony discusses three distinct sets of analyses. The first set of analyses addresses the fact that the CDR and CILC programs are no longer cost-effective at the programs' current incentive payment levels. Thus, these incentive payment levels need to be lowered to return the programs to a cost-effective position that should allow the programs to remain cost-effective for a number of years. FPL is proposing appropriate new lower incentive payment levels that will accomplish that and should allow continued growth in CDR program participation sufficient to meet FPL's DSM Goals and retain existing program participants.

The second set of analyses discussed in my testimony address the Manatee modernization project that is scheduled to be completed in the fourth Quarter of 2021. The project, which has as its two main components the early retirement of existing Manatee Units 1 & 2 and the addition of a nominal 400 MW battery storage facility at the Manatee site, is estimated to result in CPVRR savings of $101 million.

The third set of analyses I have discussed deal with three general items: changes/additions to the Gulf system of generating units, the NFRC, and the integration of the two utility systems from a resource planning perspective. The results of the analyses show significant projected net cost savings for each of these items which together result in a projected CPVRR net total cost savings for customers of more than $1.5 billion.

Thus, each of three specific items mentioned have been shown to be cost-effective and will benefit both Gulf's and FPL's customers. Separate economic analyses of the planned 2022 and 2023 solar additions, using an evaluation approach the FPSC has relied upon in previous SoBRA filings in which no additional solar is assumed to be added except in these two years, shows that these solar additions are projected to be cost-effective by approximately $397 million CPVRR.

Based on the results of these three sets of analyses, my conclusion is that each of these items in FPL's base rate request are strongly supported.

Q. Does this conclude your direct testimony?

A. Yes.

With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis

	(1)	(2)	(3)	(4)	(5)
Year	**Common to All FPL/Gulf Plans Retirements/Additions**	**"With Programs" Resource Plan**	**Reserve Margin (%)**	**"Without Programs" Resource Plan**	**Reserve Margin (%)**
2021	1,043 MW Solar, OUC PPA (100 MW), Indiantown PPA (330 MW)	--	*	--	*
2022	Manatee Batt. (469 MW), Crist 4x0 CT (938 MW), DBEC (1,163 MW), 149 MW Solar NFRC Line, Manatee 1&2 (1,618 MW), Scherer 4 (634 MW)	447 MW Solar	25.5	447 MW Solar	21.5
2023	Shell PPA (885 MW)	745 MW Solar	21.6	1,192 MW Solar, 4 x 100 MW Battery	20.0
2024	Daniel 1&2 (502 MW)	894 MW Solar	20.0	3x0 CT (704 MW), 968.5 MW Solar	21.2
2025	Crist 4 (75 MW), Pea Ridge (12 MW)	894 MW Solar	20.1	1,192 MW Solar	21.8
2026	---	968.5 MW Solar	20.0	372.5 MW Solar	20.9
2027	Crist 5 (75 MW), Broward South (4 MW)	968.5 MW Solar	20.0	372.5 MW Solar	20.1
2028	Lansing Smith A (32 MW)	1,192 MW Solar	20.0	1,192 MW Solar	20.1
2029	---	1,192 MW Solar, 3 x 100 MW Battery	20.0	3x1 CC (1,991 MW), 745 MW Solar	25.8
2030	Perdido 1&2 (3 MW)	1,192 MW Solar, 4 x 100 MW Battery	20.0	1,192 MW Solar, 1 x 100 MW Battery	24.5
	CPVRR Cost of Resource Plans =	**$81,942**		**$82,796**	
	CPVRR Cost Penalty for Removing CDR + CILC =	**---**		**$853**	

Notes:
CPVRR costs are in million $ and are discounted at 7.52% (FPL's most recent WACC) for the years 2020 thru 2068
* - Each system (FPL and Gulf) has its own separate reserve margin in 2021

Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs

Assumptions:	
Assumption (1): Projected CPVRR Net Benefits for CDR & CILC (millions)=	$853
Assumption (2): CPVRR Admin Costs (millions) =	$8
Assumption (3): Current CDR Monthly Incentive Level ($/kW) =	$8.71
Assumption (4): Discount rate =	7.52%
Assumption (5): Average Monthly MW of CDR & CILC =	697
Assumption (6): Time Period Over Which CPVRR Costs are Calculated =	2020 thru 2068
Assumption (7): CPVRR Cost of $1/kW Monthly Incentive Payment for 1 MW = (see calculation below)	$143,419

	(1)	(2)	(3)	(4)	(5)
		= (Monthly Incentive x Assumption 5 x Assumption 7) /1,000,000	= (2) + Assumption 2	= (1) / (3)	
Scenario	**CPVRR Net Benefits (Millions)**	**CPVRR Cost of Incentives Only (Millions)**	**CPVRR Total Cost: Incentives + Admin Costs (Millions)**	**RIM Benefit-to-Cost Ratio**	**Conclusion**
Scenario 1: With Current Monthly Incentive Level of $8.71/kW:	$853	$871	$879	**0.97**	CDR & CILC are no longer projected to be cost-effective with the current incentive level
Scenario 2: With Proposed Monthly Incentive Level of $5.80/kW:	$853	$580	$588	**1.45**	CDR & CILC will be projected to be cost-effective by a margin sufficient to withstand potential continued loss of program benefits for several years

Year	Annual Incentive Cost for 1 MW at $1/kw-mo.
2020	$0
2021	$0
2022	$12,000
2023	$12,000
2024	$12,000
2025	$12,000
2066	$12,000
2067	$12,000
2068	$12,000
CPVRR =	**$143,419**

(Note: rows for years 2026 thru 2065 are not shown to save space; those annual values are identical to the annual values that are shown.)

Comparison of Resource Plans: W/ 2022 Manatee Changes and W/ 2029 Manatee Changes

(Table shows resources available for Summer reserve margin in the year indicated)

Year	Resource Plan w/ 2022 Manatee Changes	Resource Plan w/ 2029 Manatee Changes
2021	447 MW Solar	447 MW Solar
2022	894 MW Solar, Dania Beach CC, Manatee Units 1 & 2 Retired, 469 MW Battery Storage	894 MW Solar, Dania Beach CC
2023	894 MW Solar	894 MW Solar
2024	745 MW Solar	745 MW Solar
2025	1,043 MW Solar	---
2026	3x1 CC (1,886 MW)	1,043 MW Solar
2027	894 MW Solar	894 MW Solar
2028	1,192 MW Solar	1,192 MW Solar
2029	1,192 MW Solar	1,192 MW Solar, 3x1 CC (1,886 MW), Manatee Units 1 & 2 Retired, 469 MW Battery Storage
2030	1,192 MW Solar, 3x1 CC (1,886 MW)	1,192 MW Solar, 3x1 CC (1,886 MW)
CPVRR Costs ($M, 2019$)* =	**$59,580**	**$59,682**
CPVRR Cost Differential ($M, 2019$)* =	**($101)**	**---**

** CPVRR costs address the years 2019 thru 2068*

Load Forecasts Used in the Current Analyses*: Summer Peaks

	(1)	(2)	(3)	(4) = (1)+(2)	(5) = (3) - (4)
Year	**FPL Only (MW)**	**Gulf Only (MW)**	**Integrated FPL & Gulf (MW)**	**Sum of FPL Only + Gulf Only (MW)**	**Difference: Integrated FPL & Gulf minus Sum of FPL Only + Gulf Only (MW)**
2021	24,621	2,462	26,947	27,083	(136)
2022	24,967	2,444	27,277	27,411	(134)
2023	25,441	2,467	27,771	27,908	(137)
2024	25,926	2,494	28,278	28,420	(142)
2025	26,307	2,513	28,675	28,820	(145)
2026	26,669	2,529	29,051	29,198	(147)
2027	26,944	2,545	29,340	29,489	(149)
2028	27,313	2,560	29,721	29,873	(152)
2029	27,802	2,589	30,233	30,391	(158)
2030	28,376	2,618	30,832	30,994	(162)
2031	28,947	2,639	31,423	31,586	(163)
2032	29,609	2,665	32,108	32,274	(166)
2033	30,289	2,694	32,815	32,983	(168)
2034	30,963	2,721	33,513	33,684	(171)
2035	31,674	2,750	34,250	34,424	(174)
2036	32,411	2,780	35,014	35,191	(177)
2037	33,137	2,809	35,766	35,946	(180)
2038	33,840	2,838	36,496	36,678	(182)
2039	34,533	2,867	37,214	37,400	(186)
2040	35,193	2,894	37,899	38,087	(188)
2041	35,485	2,911	38,205	38,396	(191)
2042	35,778	2,927	38,514	38,705	(191)
2043	36,075	2,944	38,825	39,019	(194)
2044	36,373	2,960	39,138	39,333	(195)
2045	36,674	2,972	39,450	39,646	(196)
2046	36,978	2,984	39,765	39,962	(197)
2047	37,284	2,996	40,082	40,280	(198)
2048	37,593	3,008	40,402	40,601	(199)
2049	37,904	3,019	40,724	40,923	(199)
2050	38,218	3,031	41,049	41,249	(200)
2051	38,534	3,044	41,377	41,578	(201)
2052	38,853	3,056	41,707	41,909	(202)
2053	39,175	3,068	42,040	42,243	(203)
2054	39,499	3,080	42,376	42,579	(203)
2055	39,826	3,092	42,714	42,918	(204)
2056	40,155	3,104	43,055	43,259	(204)
2057	40,488	3,117	43,399	43,605	(206)
2058	40,823	3,129	43,746	43,952	(206)
2059	41,161	3,142	44,096	44,303	(207)
2060	41,502	3,154	44,448	44,656	(208)
2061	41,845	3,167	44,803	45,012	(209)
2062	42,192	3,179	45,161	45,371	(210)
2063	42,541	3,192	45,522	45,733	(211)
2064	42,893	3,204	45,886	46,097	(211)
2065	43,248	3,217	46,253	46,465	(212)
2066	43,606	3,230	46,623	46,836	(213)
2067	43,967	3,243	46,996	47,210	(214)
2068	44,331	3,256	47,372	47,587	(215)

* Load forecasts used in resource planning analyses do not include the projected impacts of existing load management programs or of incremental load management and energy conservation utility DSM programs. Those impacts are addressed as line item adjustments to the load forecasts in the resource planning models.

Load Forecasts Used in the Current Analyses*: Winter Peaks

	(1)	(2)	(3)	(4) = (1)+(2)	(5) = (3) - (4)
Year	**FPL Only (MW)**	**Gulf Only (MW)**	**Integrated FPL & Gulf (MW)**	**Sum of FPL Only + Gulf Only (MW)**	**Difference: Integrated FPL & Gulf minus Sum of FPL Only + Gulf Only (MW)**
2021	20,068	2,439	22,242	22,507	(265)
2022	20,309	2,419	22,461	22,728	(267)
2023	20,705	2,436	22,869	23,141	(272)
2024	21,109	2,453	23,287	23,562	(276)
2025	21,433	2,469	23,624	23,903	(278)
2026	21,753	2,484	23,957	24,238	(281)
2027	21,983	2,500	24,199	24,483	(284)
2028	22,321	2,518	24,552	24,839	(287)
2029	22,672	2,536	24,916	25,208	(292)
2030	23,031	2,552	25,289	25,583	(295)
2031	23,402	2,576	25,680	25,978	(298)
2032	23,817	2,602	26,117	26,418	(302)
2033	24,239	2,628	26,561	26,866	(306)
2034	24,653	2,655	26,998	27,308	(309)
2035	25,085	2,682	27,454	27,767	(313)
2036	25,529	2,710	27,923	28,239	(316)
2037	25,968	2,739	28,386	28,707	(321)
2038	26,399	2,768	28,842	29,167	(324)
2039	26,827	2,796	29,295	29,623	(328)
2040	27,240	2,825	29,733	30,065	(332)
2041	27,465	2,852	29,979	30,317	(338)
2042	27,693	2,879	30,228	30,571	(343)
2043	27,922	2,906	30,479	30,828	(349)
2044	28,153	2,933	30,732	31,087	(355)
2045	28,386	2,945	30,975	31,331	(356)
2046	28,621	2,957	31,220	31,578	(358)
2047	28,858	2,969	31,467	31,827	(359)
2048	29,097	2,980	31,717	32,077	(361)
2049	29,338	2,992	31,968	32,330	(362)
2050	29,581	3,004	32,221	32,585	(364)
2051	29,826	3,016	32,477	32,842	(365)
2052	30,072	3,028	32,734	33,100	(366)
2053	30,321	3,040	32,994	33,361	(368)
2054	30,572	3,052	33,255	33,625	(369)
2055	30,825	3,064	33,519	33,890	(371)
2056	31,081	3,076	33,785	34,157	(372)
2057	31,338	3,089	34,053	34,427	(374)
2058	31,597	3,101	34,323	34,698	(375)
2059	31,859	3,113	34,595	34,972	(377)
2060	32,123	3,126	34,870	35,248	(378)
2061	32,389	3,138	35,147	35,527	(380)
2062	32,657	3,150	35,426	35,807	(381)
2063	32,927	3,163	35,707	36,090	(383)
2064	33,200	3,175	35,991	36,375	(384)
2065	33,474	3,188	36,277	36,663	(386)
2066	33,752	3,201	36,565	36,952	(387)
2067	34,031	3,213	36,855	37,244	(389)
2068	34,313	3,226	37,148	37,539	(390)

* Load forecasts used in resource planning analyses do not include the projected impacts of existing load management programs or of incremental load management and energy conservation utility DSM programs. Those impacts are addressed as line item adjustments to the load forecasts in the resource planning models.

Load Forecasts Used in the Current Analyses*: Annual Net Energy for Load

	(1)	(2)	(3)	(4) = (1)+(2)	(5) = (3) - (4)
Year	**FPL Only (GWh)**	**Gulf Only (GWh)**	**Integrated FPL & Gulf (GWh)**	**Sum of FPL Only + Gulf Only (GWh)**	**Difference: Integrated FPL & Gulf minus Sum of FPL Only + Gulf Only (GWh)**
2021	123,096	11,778	134,874	134,874	0
2022	123,989	11,761	135,750	135,750	(0)
2023	125,059	11,765	136,824	136,824	(0)
2024	126,034	11,778	137,812	137,812	(0)
2025	127,216	11,811	139,027	139,027	0
2026	128,223	11,836	140,059	140,059	0
2027	129,116	11,851	140,967	140,967	(0)
2028	130,772	11,860	142,632	142,632	(0)
2029	132,415	11,852	144,266	144,266	0
2030	134,215	11,909	146,124	146,124	(0)
2031	136,227	11,991	148,219	148,219	0
2032	138,520	12,081	150,601	150,601	0
2033	140,950	12,175	153,125	153,125	0
2034	143,404	12,273	155,677	155,677	0
2035	145,908	12,375	158,283	158,283	(0)
2036	148,357	12,481	160,838	160,838	0
2037	150,782	12,586	163,368	163,368	(0)
2038	153,263	12,689	165,952	165,952	(0)
2039	155,740	12,791	168,531	168,531	0
2040	158,167	12,889	171,056	171,056	0
2041	159,476	12,941	172,417	172,417	0
2042	160,797	12,992	173,788	173,788	0
2043	162,128	13,044	175,171	175,171	(0)
2044	163,470	13,095	176,565	176,565	0
2045	164,823	13,147	177,970	177,970	0
2046	166,187	13,200	179,387	179,387	(0)
2047	167,563	13,252	180,815	180,815	(0)
2048	168,950	13,305	182,255	182,255	(0)
2049	170,349	13,357	183,706	183,706	0
2050	171,759	13,411	185,169	185,169	(0)
2051	173,181	13,464	186,644	186,644	0
2052	174,614	13,517	188,132	188,131	0
2053	176,060	13,571	189,631	189,631	(0)
2054	177,517	13,625	191,142	191,142	(0)
2055	178,987	13,679	192,666	192,666	0
2056	180,468	13,733	194,202	194,202	0
2057	181,962	13,788	195,750	195,750	(0)
2058	183,469	13,843	197,311	197,311	(0)
2059	184,987	13,898	198,885	198,885	(0)
2060	186,519	13,953	200,471	200,471	0
2061	188,063	14,008	202,071	202,071	0
2062	189,619	14,064	203,683	203,683	(0)
2063	191,189	14,120	205,309	205,309	0
2064	192,772	14,176	206,948	206,947	0
2065	194,368	14,232	208,600	208,600	(0)
2066	195,977	14,289	210,265	210,265	0
2067	197,599	14,345	211,944	211,944	0
2068	199,235	14,402	213,637	213,637	0

* Load forecasts used in resource planning analyses do not include the projected impacts of existing load management programs or of incremental load management and energy conservation utility DSM programs. Those impacts are addressed as line item adjustments to the load forecasts in the resource planning models.

Fuel Cost Forecasts Used in the Current Analyses
(October 5, 2020 Forecast, Nominal $)

	FPL Area Units						Gulf Area Units				
Year	FGT Firm Gas ($/MMBTU)	Gulfstream Firm Gas ($/MMBTU)	Sabal Trail Firm Gas ($/MMBTU)	Residual Oil ($/MMBTU)	Distillate Oil ($/MMBTU)	Scherer 4 Coal Price ($/MMBTU)	Lansing Smith Gas ($/MMBTU)	Crist Gas ($/MMBTU)	Daniel Coal Price ($/MMBTU)	Crist Coal Price ($/MMBTU)	Scherer 3 Coal Price ($/MMBTU)
2021	3.00	2.93	2.96	9.28	9.81	2.54	3.08	2.84	2.86	3.05	2.54
2022	2.69	2.66	2.66	9.74	10.61	2.62	2.77	2.53	2.90	3.08	2.62
2023	2.76	2.74	2.73	10.09	12.21	2.74	2.85	2.61	2.97	3.12	2.74
2024	2.74	2.71	2.70	10.06	12.56	2.83	2.82	2.59	3.06	3.19	2.83
2025	3.03	3.00	2.99	9.54	13.25	2.91	3.12	2.88	3.13	3.25	2.91
2026	2.96	2.93	2.92	9.57	13.49	2.98	3.04	2.81	3.21	3.32	2.98
2027	3.11	3.09	3.07	9.66	13.75	3.05	3.20	2.97	3.28	3.39	3.05
2028	3.27	3.24	3.22	9.75	14.00	3.13	3.35	3.12	3.35	3.46	3.13
2029	3.42	3.39	3.37	9.85	14.26	3.19	3.51	3.27	3.41	3.50	3.19
2030	3.57	3.54	3.52	9.94	14.53	3.26	3.66	3.52	3.48	3.57	3.26
2031	3.78	3.75	3.72	10.08	14.80	3.32	3.87	3.75	3.55	3.64	3.32
2032	3.93	3.90	3.87	10.23	15.05	3.39	4.07	3.90	3.62	3.72	3.39
2033	4.14	4.10	4.07	10.37	15.30	3.47	4.29	4.10	3.70	3.80	3.47
2034	4.34	4.31	4.27	10.52	15.57	3.54	4.49	4.30	3.78	3.87	3.54
2035	4.50	4.46	4.42	10.62	15.80	3.61	4.64	4.45	3.86	3.95	3.61
2036	4.70	4.66	4.62	10.72	16.02	3.68	4.84	4.65	3.93	4.03	3.68
2037	4.85	4.82	4.77	10.82	16.23	3.76	4.99	4.80	4.01	4.15	3.76
2038	4.96	4.92	4.87	10.93	16.43	3.83	5.09	4.90	4.10	4.23	3.83
2039	5.01	4.97	4.92	11.03	16.64	3.91	5.14	4.95	4.18	4.31	3.91
2040	5.11	5.07	5.02	11.13	16.85	3.99	5.24	5.05	4.27	4.39	3.99
2041	5.16	5.12	5.07	11.20	17.03	4.06	5.29	5.10	4.36	4.47	4.06
2042	5.26	5.22	5.17	11.28	17.22	4.14	5.39	5.20	4.45	4.55	4.14
2043	5.36	5.33	5.27	11.35	17.40	4.22	5.49	5.30	4.54	4.64	4.22
2044	5.42	5.38	5.32	11.42	17.59	4.30	5.54	5.35	4.64	4.71	4.30
2045	5.52	5.48	5.42	11.50	17.78	4.35	5.64	5.45	4.72	4.79	4.35
2046	5.62	5.58	5.52	11.57	17.97	4.43	5.74	5.55	4.80	4.87	4.43
2047	5.72	5.68	5.62	11.65	18.17	4.52	5.84	5.65	4.88	4.95	4.52
2048	5.77	5.73	5.67	11.72	18.36	4.61	5.89	5.70	4.98	5.04	4.61
2049	5.88	5.84	5.77	11.80	18.56	4.70	5.99	5.80	5.07	5.12	4.70
2050	5.98	5.94	5.87	11.88	18.76	4.79	6.09	5.90	5.17	5.21	4.79
2051	6.02	5.98	5.92	11.96	18.97	4.88	6.13	5.94	5.27	5.30	4.88
2052	6.06	6.02	5.96	12.03	19.17	4.97	6.17	5.98	5.37	5.39	4.97
2053	6.10	6.06	6.00	12.11	19.38	5.07	6.22	6.02	5.48	5.48	5.07
2054	6.15	6.11	6.04	12.19	19.59	5.17	6.26	6.07	5.58	5.57	5.17
2055	6.19	6.15	6.08	12.27	19.80	3.75	6.30	6.11	5.69	5.67	5.27
2056	6.23	6.19	6.12	12.36	20.02	5.37	6.34	6.15	5.80	5.77	5.37
2057	6.28	6.24	6.17	12.44	20.23	5.47	6.38	6.19	5.91	5.86	5.47
2058	6.32	6.28	6.21	12.52	20.45	5.58	6.43	6.24	6.02	5.97	5.58
2059	6.37	6.32	6.25	12.60	20.68	5.68	6.47	6.28	6.14	6.07	5.68
2060	6.41	6.37	6.30	12.69	20.90	5.79	6.51	6.32	6.26	6.17	5.79
2061	6.45	6.41	6.34	12.77	21.13	5.91	6.56	6.37	6.38	6.28	5.91
2062	6.50	6.46	6.39	12.85	21.36	6.02	6.60	6.41	6.50	6.39	6.02
2063	6.55	6.50	6.43	12.94	21.59	6.14	6.65	6.46	6.63	6.50	6.14
2064	6.59	6.55	6.47	13.03	21.83	6.25	6.69	6.50	6.76	6.61	6.25
2065	6.64	6.59	6.52	13.11	22.07	6.38	6.74	6.55	6.89	6.72	6.38
2066	6.68	6.64	6.57	13.20	22.31	6.50	6.78	6.59	7.02	6.84	6.50
2067	6.73	6.69	6.61	13.29	22.55	6.62	6.83	6.64	7.15	6.95	6.62
2068	6.78	6.73	6.66	13.38	22.80	6.74	6.87	6.69	7.28	7.06	6.74

CO_2 Compliance Cost Forecast Used in the Current Analyses
(2019 Q4 ICF Forecast, Nominal $)

Year	CO_2 Cost ($/ton)
2021	0.0
2022	0.0
2023	0.0
2024	0.0
2025	0.0
2026	1.1
2027	1.8
2028	3.1
2029	4.4
2030	5.4
2031	6.4
2032	7.6
2033	8.9
2034	10.3
2035	13.2
2036	16.4
2037	20.1
2038	24.1
2039	28.5
2040	33.4
2041	38.2
2042	43.4
2043	49.2
2044	55.5
2045	62.5
2046	70.0
2047	74.0
2048	78.3
2049	82.7
2050	87.5
2051	89.3
2052	91.2
2053	93.1
2054	95.1
2055	97.1
2056	99.1
2057	101.2
2058	103.3
2059	105.5
2060	107.7
2061	110.0
2062	112.3
2063	114.6
2064	117.0
2065	119.5
2066	122.0
2067	124.6
2068	127.2

Results of the Initial Step 1 and Step 2 Analyses: Step 1

Resource Options (Year or Years It Can Be Selected)	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
	Resource Options Eligible for Selection in Each Case (X = Eligible)							
- New CT units (2022-on) & new CC Unit (2024-on)	X	X	X	X	X	X	X	X
- Daniel 1&2 Retirement in 1/2024		X	X	X	X	X	X	X
- 75 MW of Solar (2020)			X	X	X	X	X	X
- Crist 6&7 Coal to Gas Conversion (2020)				X	X	X	X	X
- Lansing Smith Upgrade (2020)					X	X	X	X
- 2 Addl. 75 MW Solar units (2020 or 2021)						X	X	X
- 3 Addl. 75 MW Solar units (2022-on)							X	X
- Stand-alone Batteries (2020-on)								X

Year	Retirements Common to All Plans	Base Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
		Resource Additions by Plan (2019 thru 2030)							
2020	---	---	---	75 MW PV	75 MW PV, Crist Conversion	75 MW PV, Crist Conversion, Lansing Smith Upgrade	75 MW PV, Crist Conversion, Lansing Smith Upgrade	75 MW PV, Crist Conversion, Lansing Smith Upgrade	75 MW PV, Crist Conversion, Lansing Smith Upgrade
2021	---	---	---	---	---	---	2 x 75 MW PV	2 x 75 MW PV	2 x 75 MW PV
2022	---	---	---	---	---	---	---	---	---
2023	Shell PPA (885 MW)	704 MW CT	704 MW CT	704 MW CT	704 MW CT	704 MW CT	704 MW CT	469 MW CT	469 MW CT
2024	---	---	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC	Daniel 1&2 Retire, Escambia 627 MW CC
2025	Crist 4 (75 MW) , Pea Ridge 1, 2 & 3 (12 MW)	235 MW CT	---	---	---	---	---	---	---
2026	---	---	---	---	---	---	---	3 x 75 MW PV	---
2027	Crist 5 (75 MW)	---	235 MW CT	---	---	---	---	---	75 MW PV
2028	Lansing Smith A (32 MW)	---	---	235 MW CT	---	---	---	---	2 x 75 MW PV
2029	---	---	---	---	---	---	---	---	---
2030	Perdido 1&2 (3 MW)	---	---	---	235 MW CT	---	---	235 MW CT	20 MW 2-Hour Battery, 20 MW 3-Hour Battery, 20 MW 4-Hour Battery
	Total CPVRR Cost =	**7,887**	**7,658**	**7,611**	**7,375**	**7,334**	**7,290**	**7,262**	**7,196**
	Case-to-Case CPVRR Change =	---	**(229)**	**(47)**	**(236)**	**(41)**	**(44)**	**(28)**	**(66)**
	Cumulative CPVRR Change =	---	**(229)**	**(276)**	**(512)**	**(553)**	**(597)**	**(625)**	**(691)**

Notes:
CPVRR costs are in million $ and are discounted at 7.25% (Gulf's WACC at the time of this analysis) for the years 2019 thru 2048

Results of the Initial Step 1 and Step 2 Analyses: Step 2

Year	Retirements Common to All Plans	Step 1: Gulf Stand Alone Optimized Resource Plan (Case 7, from page 1 of 2)	Step 2: Re-optimize Gulf resource plan assuming NFRC is in place, Daniel early retirement, and w/ FPL IRP plan locked in place
		Gulf Power Resource Additions by Resource Plan	
2020	---	75 MW PV, Crist Conversion, Lansing Smith Upgrade	Crist Conversion, Lansing Smith Upgrade
2021	---	2 x 75 MW PV	2 x 75 MW PV
2022	---	---	NFRC Line
2023	Shell PPA (885 MW)	469 MW CT	469 MW CT
2024	Daniel 1&2 (510 MW)	Escambia 627 MW CC	469 MW CT
2025	Crist 4 (75 MW) , Pea Ridge (12 MW)	---	---
2026	---	---	---
2027	Crist 5 (75 MW)	75 MW PV	75 MW PV
2028	Lansing Smith A (32 MW)	2 x 75 MW PV	2 x 75 MW PV
2029	---	---	---
2030	Perdido 1&2 (3 MW)	20 MW 2-Hour Battery, 20 MW 3-Hour Battery, 20 MW 4-Hour Battery	20 MW 2-Hour Battery, 20 MW 3-Hour Battery, 20 MW 4-Hour Battery
	Gulf System CPVRR Costs =	**7,196**	**4,724**
	Costs of Energy from FPL to Gulf CPVRR =	**---**	**1,854**
	NFRC Line (Capital & FOM Only) CPVRR Cost =	**---**	**424**
	Total CPVRR Costs =	---	**7,002**
	CPVRR Cost Difference from Step 1, Case 7 =	---	**(194)**

Notes:
CPVRR costs are in million $ and are discounted at 7.25% (Gulf's WACC at the time of this analysis) for the years 2019 thru 2048

Results of the Current Step 1 Analysis

Current Step 1 Analysis					
Eligible Resource Options (Years It Can Be Selected)		**Case 1a**		**Case 1b**	
New 1x0, 2x0 & 3x0 CT units (2024-2030) & 1x1 Escambia CC Unit (2026-2030)		X		X	
20 Addl. 75 MW Solar units (2022-2030)				X	
Five 20 MW Batteries (2023-2030)				X	
Daniels 1&2 Early Retirement (2024)				X	
Common to all Plans Retirements / Additions	**Year**	**GULF Case 1a**	**RM%**	**GULF Case 1b**	**RM %**
---	2021	--	40.7	--	40.7
Crist 4x0 CT (938 MW) 149 MW Solar	2022	--	84.1	--	84.1
Shell PPA (885 MW)	2023	--	46.8	--	46.8
---	2024	--	45.7	Daniel 1&2 Retired (502 MW), 1 x 20 MW Battery, 223.5 MW Solar	30.3
Crist 4 (75 MW) , Pea Ridge (12 MW)	2025	--	41.0	149 MW Solar, 2 x 20 MW Battery	30.0
---	2026	--	40.1	2 x 20 MW Battery	30.7
Crist 5 (75 MW)	2027	--	36.1	1x1 Escambia CC (627 MW)	51.7
Lansing Smith A (32 MW)	2028	--	34.0	--	49.5
---	2029	--	32.4	--	47.7
Perdido 1&2 (3 MW)	2030	1x1 Escambia CC (627 MW)	55.0	--	45.9
Total CPVRR =		**10,199**		**9,342**	
CPVRR Difference From Case 1a =		**--**		**(856)**	

Notes:
CPVRR costs are in million $ and are discounted at 6.95% (Gulf's most recent WACC) for the years 2020 thru 2068

Results of the Current Step 2 Analysis

Current Step 2 Analysis			
Gulf **Retirements / Additions**	**Year**	**Resource Additions**	**RM%**
---	2021	--	40.7
850 MW NFRC Line,149 MW Solar Crist 4x0 CT (938 MW)	2022	--	84.1
Shell PPA (885 MW)	2023	--	46.8
---	2024	Daniel 1&2 Retired (502 MW)	25.3
Crist 4 (75 MW) , Pea Ridge (12 MW)	2025	--	20.8
---	2026	74.5 MW Solar	21.6
Crist 5 (75 MW)	2027	149 MW Solar	20.2
Lansing Smith A (32 MW)	2028	74.5 MW Solar, 1 x 20 MW Battery	20.3
---	2029	74.5 MW Solar	20.1
Perdido 1&2 (3 MW)	2030	1x1 Escambia CC (627 MW), 4 x 20 MW Battery	46.0

Gulf System CPVRR Cost =	**6,046**
Costs of Energy from FPL to Gulf CPVRR =	**2,186**
NFRC Line Project CPVRR Cost =	**722**
Total CPVRR Cost =	**8,953**
CPVRR Cost Difference from Step 1, Case 1b =	**(389)**

Notes:
CPVRR costs are in million $ and are discounted at 6.95% (Gulf's most recent WACC) for the years 2020 thru 2068

Projected CPVRR Costs for: the NFRC Line Project, Wheeling Through the Southern Company System, and Wheeling Through the DEF System

Alternative	Projected CPVRR Costs ($)	Cost Differential
NFRC Line Project	$721,638,914	---
Wheeling Through Southern	$1,290,485,599	$568,846,685
Wheeling Through DEF	$1,282,382,503	$560,743,589

Projected CPVRR Costs for: the NFRC Line Project, Wheeling Through the Southern Company System, and Wheeling Through the DEF System

Discount Rate = 6.95%

Year	Annual Discount Factor	NFRC Line Capital Costs Nominal ($)	Other NFRC Line Project Costs* Nominal ($)	Total NFRC Project Costs Nominal ($)	Total NFRC Project Costs NPV ($)	Cumulative Total NFRC Project Costs NPV ($)
2020	1.000	$0	$0	$0	$0	$0
2021	0.935	$0	$0	$0	$0	$0
2022	0.874	$29,594,919	$8,608,832	$38,203,750	$33,400,651	$33,400,651
2023	0.817	$66,886,442	$14,522,066	$81,408,508	$66,549,256	$99,949,907
2024	0.764	$64,840,049	$14,365,208	$79,205,257	$60,541,320	$160,491,227
2025	0.715	$62,900,525	$14,330,682	$77,231,207	$55,196,961	$215,688,188
2026	0.668	$61,057,184	$14,446,826	$75,504,010	$50,456,467	$266,144,655
2027	0.625	$59,301,118	$9,419,380	$68,720,498	$42,939,560	$309,084,214
2028	0.584	$57,606,206	$9,193,014	$66,799,220	$39,027,178	$348,111,393
2029	0.546	$55,930,887	$8,943,428	$64,874,315	$35,439,943	$383,551,335
2030	0.511	$54,254,973	$8,994,508	$63,249,482	$32,307,374	$415,858,710
2031	0.478	$52,579,060	$8,411,897	$60,990,957	$29,129,606	$444,988,316
2032	0.447	$50,903,147	$8,531,064	$59,434,211	$26,541,785	$471,530,101
2033	0.418	$49,227,234	$7,968,350	$57,195,584	$23,882,545	$495,412,646
2034	0.390	$47,551,320	$8,044,838	$55,596,159	$21,706,378	$517,119,024
2035	0.365	$45,875,407	$7,419,788	$53,295,195	$19,456,069	$536,575,093
2036	0.341	$44,199,494	$7,238,232	$51,437,725	$17,557,928	$554,133,021
2037	0.319	$42,698,727	$7,059,393	$49,758,120	$15,881,077	$570,014,098
2038	0.298	$41,548,848	$7,191,242	$48,740,090	$14,545,437	$584,559,535
2039	0.279	$40,574,115	$6,664,799	$47,238,913	$13,181,500	$597,741,034
2040	0.261	$39,599,382	$6,594,521	$46,193,902	$12,052,414	$609,793,448
2041	0.244	$38,624,649	$6,542,705	$45,167,353	$11,018,907	$620,812,355
2042	0.228	$37,649,916	$7,146,843	$44,796,759	$10,218,448	$631,030,802
2043	0.213	$36,675,183	$6,210,786	$42,885,969	$9,146,986	$640,177,789
2044	0.199	$35,700,450	$6,141,393	$41,841,843	$8,344,457	$648,522,245
2045	0.186	$34,725,717	$6,008,287	$40,734,003	$7,595,718	$656,117,963
2046	0.174	$33,750,984	$6,290,796	$40,041,780	$6,981,513	$663,099,477
2047	0.163	$32,776,251	$5,752,113	$38,528,363	$6,281,180	$669,380,657
2048	0.152	$31,801,518	$5,638,539	$37,440,057	$5,707,181	$675,087,838
2049	0.143	$30,826,785	$5,504,661	$36,331,446	$5,178,361	$680,266,198
2050	0.133	$29,852,052	$5,769,152	$35,621,204	$4,747,256	$685,013,455
2051	0.125	$28,877,319	$5,270,934	$34,148,253	$4,255,269	$689,268,724
2052	0.117	$27,902,586	$5,684,587	$33,587,173	$3,913,420	$693,182,144
2053	0.109	$26,927,853	$5,076,676	$32,004,528	$3,486,735	$696,668,879
2054	0.102	$25,953,119	$5,363,372	$31,316,491	$3,190,106	$699,858,984
2055	0.095	$24,978,386	$4,728,450	$29,706,836	$2,829,520	$702,688,505
2056	0.089	$24,003,653	$4,681,809	$28,685,462	$2,554,717	$705,243,222
2057	0.083	$23,028,920	$4,601,146	$27,630,067	$2,300,845	$707,544,066
2058	0.078	$22,054,187	$4,872,201	$26,926,389	$2,096,563	$709,640,629
2059	0.073	$21,079,454	$4,195,541	$25,274,995	$1,840,117	$711,480,746
2060	0.068	$20,104,721	$4,162,328	$24,267,049	$1,651,946	$713,132,692
2061	0.064	$19,304,623	$4,045,132	$23,349,755	$1,486,228	$714,618,920
2062	0.060	$18,523,929	$4,972,138	$23,496,067	$1,398,373	$716,017,293
2063	0.056	$17,743,235	$4,069,985	$21,813,220	$1,213,869	$717,231,162
2064	0.052	$16,962,540	$3,968,429	$20,930,969	$1,089,096	$718,320,258
2065	0.049	$16,181,846	$3,867,395	$20,049,241	$975,437	$719,295,695
2066	0.045	$15,401,152	$3,766,903	$19,168,054	$871,974	$720,167,669
2067	0.043	$14,620,457	$3,673,528	$18,293,986	$778,141	$720,945,810
2068	0.040	$13,839,763	$3,587,291	$17,427,054	$693,104	**$721,638,914**
CPVRR Total Cost =		**$605,547,617**	**$116,091,297**	**$721,638,914**		

* Other NFRC Line Project costs are comprised of: NFRC line annual O&M, capital payments to Southern Company for improvements to their transmission system, and projected short-term PPA payments.

Projected CPVRR Costs for: the NFRC Line Project, Wheeling Through the Southern Company System, and Wheeling Through the DEF System: Wheeling Through the Southern Company System

Discount Rate = 6.95%
–on Escalation Rate = 5.9% (for the Firm Point-to-Point charges)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
					From Southern OATT								
Year	Annual Discount Factor	Reserved Capacity kW[1]	Energy Losses Not Accounted for in the Rates[2]	Reserved Capacity kW + Losses[2]	Firm Point-to-Point Charge ($/kW-month)[3]	Schedule 1 Charge ($/kW-month)[4]	Schedule 2 Charge ($/kW-month)[5]	Firm Point-to-Point ($)	Schedule 1 Charge[4] ($)	Schedule 2 Charge[5] ($)	Total Annual Charge (Nominal $)	Total Annual Charge (NPV $)	Cumulative Annual Charges (NPV $)
2020	1.000	0	0.0000	0	3.12235	0.0806	0.11	$0	$0	$0	$0	$0	$0
2021	0.935	0	0.0000	0	3.30780	0.0806	0.11	$0	$0	$0	$0	$0	$0
2022	0.874	624,000	0.0000	624,000	3.65193	0.0806	0.11	$13,672,826	$301,766	$411,840	$14,386,432	$12,577,724	$12,577,724
2023	0.817	624,000	0.0000	624,000	4.13583	0.0806	0.11	$30,969,095	$603,533	$823,680	$32,396,308	$26,483,106	$39,060,830
2024	0.764	624,000	0.0000	624,000	4.46279	0.0806	0.11	$33,417,372	$603,533	$823,680	$34,844,584	$26,633,802	$65,694,632
2025	0.715	624,000	0.0000	624,000	4.73390	0.0806	0.11	$35,447,443	$603,533	$823,680	$36,874,656	$26,354,230	$92,048,862
2026	0.668	827,000	0.0000	827,000	5.01507	0.0806	0.11	$49,769,525	$799,874	$1,091,640	$51,661,039	$34,523,113	$126,571,975
2027	0.625	827,000	0.0000	827,000	5.31293	0.0806	0.11	$52,725,554	$799,874	$1,091,640	$54,617,069	$34,127,123	$160,699,098
2028	0.584	827,000	0.0000	827,000	5.62849	0.0806	0.11	$55,857,155	$799,874	$1,091,640	$57,748,670	$33,739,430	$194,438,527
2029	0.546	827,000	0.0000	827,000	5.96279	0.0806	0.11	$59,174,755	$799,874	$1,091,640	$61,066,270	$33,359,660	$227,798,188
2030	0.511	827,000	0.0000	827,000	6.31695	0.0806	0.11	$62,689,403	$799,874	$1,091,640	$64,580,917	$32,987,462	$260,785,650
2031	0.478	827,000	0.0000	827,000	6.69214	0.0806	0.11	$66,412,800	$799,874	$1,091,640	$68,304,314	$32,622,505	$293,408,154
2032	0.447	827,000	0.0000	827,000	7.08962	0.0806	0.11	$70,357,346	$799,874	$1,091,640	$72,248,860	$32,264,477	$325,672,632
2033	0.418	827,000	0.0000	827,000	7.51070	0.0806	0.11	$74,536,176	$799,874	$1,091,640	$76,427,690	$31,913,089	$357,585,720
2034	0.390	827,000	0.0000	827,000	7.95679	0.0806	0.11	$78,963,205	$799,874	$1,091,640	$80,854,719	$31,568,064	$389,153,784
2035	0.365	827,000	0.0000	827,000	8.42938	0.0806	0.11	$83,653,175	$799,874	$1,091,640	$85,544,689	$31,229,145	$420,382,929
2036	0.341	827,000	0.0000	827,000	8.93004	0.0806	0.11	$88,621,702	$799,874	$1,091,640	$90,513,216	$30,896,089	$451,279,018
2037	0.319	827,000	0.0000	827,000	9.46043	0.0806	0.11	$93,885,332	$799,874	$1,091,640	$95,776,846	$30,568,668	$481,847,686
2038	0.298	827,000	0.0000	827,000	10.02233	0.0806	0.11	$99,461,591	$799,874	$1,091,640	$101,353,106	$30,246,666	$512,094,352
2039	0.279	827,000	0.0000	827,000	10.61760	0.0806	0.11	$105,369,050	$799,874	$1,091,640	$107,260,564	$29,929,881	$542,024,234
2040	0.261	827,000	0.0000	827,000	11.24822	0.0806	0.11	$111,627,378	$799,874	$1,091,640	$113,518,892	$29,618,123	$571,642,357
2041	0.244	827,000	0.0000	827,000	11.91631	0.0806	0.11	$118,257,415	$799,874	$1,091,640	$120,148,929	$29,311,211	$600,953,568
2042	0.228	827,000	0.0000	827,000	12.62407	0.0806	0.11	$125,281,239	$799,874	$1,091,640	$127,172,754	$29,008,976	$629,962,544
2043	0.213	827,000	0.0000	827,000	13.37387	0.0806	0.11	$132,722,239	$799,874	$1,091,640	$134,613,753	$28,711,259	$658,673,803
2044	0.199	827,000	0.0000	827,000	14.16820	0.0806	0.11	$140,605,192	$799,874	$1,091,640	$142,496,707	$28,417,907	$687,091,711
2045	0.186	827,000	0.0000	827,000	15.00971	0.0806	0.11	$148,956,349	$799,874	$1,091,640	$150,847,863	$28,128,780	$715,220,491
2046	0.174	827,000	0.0000	827,000	15.90120	0.0806	0.11	$157,803,517	$799,874	$1,091,640	$159,695,031	$27,843,743	$743,064,233
2047	0.163	827,000	0.0000	827,000	16.84564	0.0806	0.11	$167,176,157	$799,874	$1,091,640	$169,067,671	$27,562,668	$770,626,901
2048	0.152	827,000	0.0000	827,000	17.84618	0.0806	0.11	$177,105,478	$799,874	$1,091,640	$178,996,993	$27,285,435	$797,912,336
2049	0.143	827,000	0.0000	827,000	18.90614	0.0806	0.11	$187,624,546	$799,874	$1,091,640	$189,516,060	$27,011,931	$824,924,267
2050	0.133	827,000	0.0000	827,000	20.02906	0.0806	0.11	$198,768,387	$799,874	$1,091,640	$200,659,902	$26,742,049	$851,666,316
2051	0.125	827,000	0.0000	827,000	21.21867	0.0806	0.11	$210,574,110	$799,874	$1,091,640	$212,465,624	$26,475,686	$878,142,002
2052	0.117	827,000	0.0000	827,000	22.47894	0.0806	0.11	$223,081,025	$799,874	$1,091,640	$224,972,540	$26,212,747	$904,354,749
2053	0.109	827,000	0.0000	827,000	23.81407	0.0806	0.11	$236,330,782	$799,874	$1,091,640	$238,222,296	$25,953,139	$930,307,889
2054	0.102	827,000	0.0000	827,000	25.22849	0.0806	0.11	$250,367,499	$799,874	$1,091,640	$252,259,013	$25,696,777	$956,004,666
2055	0.095	827,000	0.0000	827,000	26.72692	0.0806	0.11	$265,237,918	$799,874	$1,091,640	$267,129,432	$25,443,577	$981,448,243
2056	0.089	827,000	0.0000	827,000	28.31434	0.0806	0.11	$280,991,556	$799,874	$1,091,640	$282,883,070	$25,193,462	$1,006,641,705
2057	0.083	827,000	0.0000	827,000	29.99606	0.0806	0.11	$297,680,871	$799,874	$1,091,640	$299,572,385	$24,946,358	$1,031,588,063
2058	0.078	827,000	0.0000	827,000	31.77765	0.0806	0.11	$315,361,438	$799,874	$1,091,640	$317,252,952	$24,702,193	$1,056,290,257
2059	0.073	827,000	0.0000	827,000	33.66507	0.0806	0.11	$334,092,131	$799,874	$1,091,640	$335,983,645	$24,460,901	$1,080,751,157
2060	0.068	827,000	0.0000	827,000	35.66458	0.0806	0.11	$353,935,321	$799,874	$1,091,640	$355,826,835	$24,222,417	$1,104,973,574
2061	0.064	827,000	0.0000	827,000	37.78286	0.0806	0.11	$374,957,085	$799,874	$1,091,640	$376,848,599	$23,986,681	$1,128,960,255
2062	0.060	827,000	0.0000	827,000	40.02695	0.0806	0.11	$397,227,424	$799,874	$1,091,640	$399,118,938	$23,753,634	$1,152,713,889
2063	0.056	827,000	0.0000	827,000	42.40432	0.0806	0.11	$420,820,495	$799,874	$1,091,640	$422,712,009	$23,523,220	$1,176,237,109
2064	0.052	827,000	0.0000	827,000	44.92290	0.0806	0.11	$445,814,861	$799,874	$1,091,640	$447,706,376	$23,295,387	$1,199,532,497
2065	0.049	827,000	0.0000	827,000	47.59107	0.0806	0.11	$472,293,753	$799,874	$1,091,640	$474,185,267	$23,070,084	$1,222,602,581
2066	0.045	827,000	0.0000	827,000	50.41771	0.0806	0.11	$500,345,341	$799,874	$1,091,640	$502,236,855	$22,847,263	$1,245,449,844
2067	0.043	827,000	0.0000	827,000	53.41224	0.0806	0.11	$530,063,035	$799,874	$1,091,640	$531,954,550	$22,626,876	$1,268,076,720
2068	0.040	827,000	0.0000	827,000	56.58462	0.0806	0.11	$561,545,793	$799,874	$1,091,640	$563,437,308	$22,408,879	**$1,290,485,599**
							CPVRR Total Cost =	**$1,268,211,842**	**$9,419,018**	**$12,854,739**	**$1,290,485,599**		

(14)	(15)
Year	Annual Change in Firm Point-to-Point Charges in OATT (%)
2020	
2021	5.9%
2022	10.4%
2023	13.3%
2024	7.9%
2025	6.1%
High Value =	13.3%
Avg. Value =	8.7%
Low Value =	5.9%

Notes:

(1) For the "Reserved Capacity" value, the projected annual average hourly kW amount is used for purposes of this calculation although the maximum hourly flow is projected to be 850,000 kW in a number of hours. The smaller kW value was chosen to help ensure that the wheeling cost projection was conservative.

(2) In accordance with Southern Company's current Open Access Transmission Tariff ("OATT"), as of January 1, 2021, Transmission Provider's rates for bulk transmission service include demand lossesi(*e.* , demand is calculated at the point output) for service above the 44/46 kV level and no adjustment to the Transmission Customer's demand for billing will be required. As such, a gross up of the reservation to account for losses is not required.

(3) 2020 Firm Point to Point charge is posted to Southern Company's OASIS site under file "Tariff Rate Summary effective January 1, 2021." A projection for 2021-2025 of Firm Point-to-Point rates is posted to Southern Company's OASIS site under file "OATT Rate Forecast (2021-2025). For the years 2026-on, the lowest projected annual escalation rate was used (See Column (15)).

(4) In accordance with Southern Company's current OATT, as of January 1, 2021, "Schedule 1" ancillary service charges for Scheduling, System Control and Dispatch Service must be purchased from the Transmission Provider or the Control Area operator. The current effective rate is posted to Southern Company's OASIS site.

(5) In accordance with Southern Company's current OATT, as of January 1, 2021, "Schedule 2" ancillary service charges for Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. In a wheeling scenario, Gulf Power would expect to purchase Schedule 2 ancillary service from Transmission Provider.

Projected CPVRR Costs for: the NFRC Line Project, Wheeling Through the Southern Company System, and Wheeling Through the DEF System: Wheeling Through the DEF System

Discount Rate = 6.95%
8-on Escalation Rate = 4.7% (for the Firm Point-to-Point charges)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
					From DEF OATT								
Year	Annual Discount Factor	Reserved Capacity kW[1]	Energy Losses Not Accounted for in the Rates[2]	Reserved Capacity kW + Losses[2]	Firm Point-to-Point Charge ($/kW-month)[3]	Schedule 1 Charge ($/kW-month)[4]	Schedule 2 Charge ($/kW-month)[5]	Firm Point-to-Point ($)	Schedule 1 Charge[4] ($)	Schedule 2 Charge[5] ($)	Total Annual Charge (Nominal $)	Total Annual Charge (NPV $)	Cumulative Annual Charges (NPV $)
2020	1.000	0	0.0140	0	2.95785	0.10587	0.21324	$0	$0	$0	$0	$0	$0
2021	0.935	0	0.0140	0	3.31485	0.10587	0.21324	$0	$0	$0	$0	$0	$0
2022	0.874	624,000	0.0140	633,000	3.73785	0.10587	0.21324	$14,196,349	$402,094	$809,886	$15,408,329	$13,471,144	$13,471,144
2023	0.817	624,000	0.0140	633,000	4.11085	0.10587	0.21324	$30,045,462	$804,189	$1,619,771	$32,469,421	$26,542,875	$40,014,019
2024	0.764	624,000	0.0140	633,000	4.30300	0.10587	0.21324	$32,077,429	$804,189	$1,619,771	$34,501,389	$26,371,477	$66,385,496
2025	0.715	624,000	0.0140	633,000	4.77300	0.10587	0.21324	$34,768,158	$804,189	$1,619,771	$37,192,118	$26,581,119	$92,966,615
2026	0.668	827,000	0.0140	839,000	5.08000	0.10587	0.21324	$49,857,575	$1,065,899	$2,146,900	$53,070,374	$35,464,919	$128,431,533
2027	0.625	827,000	0.0140	839,000	5.70934	0.10587	0.21324	$54,841,543	$1,065,899	$2,146,900	$58,054,342	$36,274,881	$164,706,414
2028	0.584	827,000	0.0140	839,000	6.41664	0.10587	0.21324	$61,635,612	$1,065,899	$2,146,900	$64,848,412	$37,887,426	$202,593,840
2029	0.546	827,000	0.0140	839,000	7.21157	0.10587	0.21324	$69,271,368	$1,065,899	$2,146,900	$72,484,167	$39,597,100	$242,190,940
2030	0.511	827,000	0.0140	839,000	7.54866	0.10587	0.21324	$74,585,804	$1,065,899	$2,146,900	$77,798,603	$39,738,960	$281,929,900
2031	0.478	827,000	0.0140	839,000	7.90150	0.10587	0.21324	$78,072,130	$1,065,899	$2,146,900	$81,284,929	$38,822,115	$320,752,015
2032	0.447	827,000	0.0140	839,000	8.27084	0.10587	0.21324	$81,721,415	$1,065,899	$2,146,900	$84,934,214	$37,929,429	$358,681,444
2033	0.418	827,000	0.0140	839,000	8.65744	0.10587	0.21324	$85,541,277	$1,065,899	$2,146,900	$88,754,077	$37,060,085	$395,741,530
2034	0.390	827,000	0.0140	839,000	9.06211	0.10587	0.21324	$89,539,689	$1,065,899	$2,146,900	$92,752,488	$36,213,303	$431,954,833
2035	0.365	827,000	0.0140	839,000	9.48569	0.10587	0.21324	$93,724,997	$1,065,899	$2,146,900	$96,937,796	$35,388,339	$467,343,172
2036	0.341	827,000	0.0140	839,000	9.92908	0.10587	0.21324	$98,105,936	$1,065,899	$2,146,900	$101,318,735	$34,584,482	$501,927,654
2037	0.319	827,000	0.0140	839,000	10.39319	0.10587	0.21324	$102,691,651	$1,065,899	$2,146,900	$105,904,451	$33,801,050	$535,728,704
2038	0.298	827,000	0.0140	839,000	10.87899	0.10587	0.21324	$107,491,714	$1,065,899	$2,146,900	$110,704,514	$33,037,394	$568,766,098
2039	0.279	827,000	0.0140	839,000	11.38750	0.10587	0.21324	$112,516,144	$1,065,899	$2,146,900	$115,728,944	$32,292,890	$601,058,988
2040	0.261	827,000	0.0140	839,000	11.91978	0.10587	0.21324	$117,775,428	$1,065,899	$2,146,900	$120,988,228	$31,566,941	$632,625,929
2041	0.244	827,000	0.0140	839,000	12.47694	0.10587	0.21324	$123,280,544	$1,065,899	$2,146,900	$126,493,344	$30,858,978	$663,484,907
2042	0.228	827,000	0.0140	839,000	13.06014	0.10587	0.21324	$129,042,984	$1,065,899	$2,146,900	$132,255,783	$30,168,450	$693,653,357
2043	0.213	827,000	0.0140	839,000	13.67061	0.10587	0.21324	$135,074,773	$1,065,899	$2,146,900	$138,287,573	$29,494,834	$723,148,191
2044	0.199	827,000	0.0140	839,000	14.30960	0.10587	0.21324	$141,388,504	$1,065,899	$2,146,900	$144,601,303	$28,837,624	$751,985,815
2045	0.186	827,000	0.0140	839,000	14.97847	0.10587	0.21324	$147,997,354	$1,065,899	$2,146,900	$151,210,154	$28,196,337	$780,182,152
2046	0.174	827,000	0.0140	839,000	15.67860	0.10587	0.21324	$154,915,118	$1,065,899	$2,146,900	$158,127,918	$27,570,507	$807,752,659
2047	0.163	827,000	0.0140	839,000	16.41146	0.10587	0.21324	$162,156,236	$1,065,899	$2,146,900	$165,369,035	$26,959,688	$834,712,348
2048	0.152	827,000	0.0140	839,000	17.17857	0.10587	0.21324	$169,735,821	$1,065,899	$2,146,900	$172,948,621	$26,363,450	$861,075,798
2049	0.143	827,000	0.0140	839,000	17.98154	0.10587	0.21324	$177,669,696	$1,065,899	$2,146,900	$180,882,495	$25,781,380	$886,857,178
2050	0.133	827,000	0.0140	839,000	18.82204	0.10587	0.21324	$185,974,419	$1,065,899	$2,146,900	$189,187,218	$25,213,079	$912,070,256
2051	0.125	827,000	0.0140	839,000	19.70183	0.10587	0.21324	$194,667,325	$1,065,899	$2,146,900	$197,880,125	$24,658,164	$936,728,420
2052	0.117	827,000	0.0140	839,000	20.62274	0.10587	0.21324	$203,766,560	$1,065,899	$2,146,900	$206,979,359	$24,116,266	$960,844,686
2053	0.109	827,000	0.0140	839,000	21.58670	0.10587	0.21324	$213,291,115	$1,065,899	$2,146,900	$216,503,915	$23,587,029	$984,431,715
2054	0.102	827,000	0.0140	839,000	22.59572	0.10587	0.21324	$223,260,872	$1,065,899	$2,146,900	$226,473,672	$23,070,111	$1,007,501,826
2055	0.095	827,000	0.0140	839,000	23.65190	0.10587	0.21324	$233,696,640	$1,065,899	$2,146,900	$236,909,440	$22,565,180	$1,030,067,006
2056	0.089	827,000	0.0140	839,000	24.75745	0.10587	0.21324	$244,620,202	$1,065,899	$2,146,900	$247,833,002	$22,071,916	$1,052,138,922
2057	0.083	827,000	0.0140	839,000	25.91467	0.10587	0.21324	$256,054,358	$1,065,899	$2,146,900	$259,267,158	$21,590,012	$1,073,728,934
2058	0.078	827,000	0.0140	839,000	27.12599	0.10587	0.21324	$268,022,976	$1,065,899	$2,146,900	$271,235,775	$21,119,168	$1,094,848,102
2059	0.073	827,000	0.0140	839,000	28.39392	0.10587	0.21324	$280,551,036	$1,065,899	$2,146,900	$283,763,835	$20,659,098	$1,115,507,200
2060	0.068	827,000	0.0140	839,000	29.72113	0.10587	0.21324	$293,664,688	$1,065,899	$2,146,900	$296,877,488	$20,209,522	$1,135,716,722
2061	0.064	827,000	0.0140	839,000	31.11037	0.10587	0.21324	$307,391,306	$1,065,899	$2,146,900	$310,604,105	$19,770,172	$1,155,486,894
2062	0.060	827,000	0.0140	839,000	32.56454	0.10587	0.21324	$321,759,539	$1,065,899	$2,146,900	$324,972,339	$19,340,786	$1,174,827,680
2063	0.056	827,000	0.0140	839,000	34.08669	0.10587	0.21324	$336,799,380	$1,065,899	$2,146,900	$340,012,180	$18,921,112	$1,193,748,792
2064	0.052	827,000	0.0140	839,000	35.67999	0.10587	0.21324	$352,542,220	$1,065,899	$2,146,900	$355,755,020	$18,510,907	$1,212,259,699
2065	0.049	827,000	0.0140	839,000	37.34776	0.10587	0.21324	$369,020,920	$1,065,899	$2,146,900	$372,233,719	$18,109,933	$1,230,369,632
2066	0.045	827,000	0.0140	839,000	39.09348	0.10587	0.21324	$386,269,875	$1,065,899	$2,146,900	$389,482,674	$17,717,961	$1,248,087,593
2067	0.043	827,000	0.0140	839,000	40.92081	0.10587	0.21324	$404,325,089	$1,065,899	$2,146,900	$407,537,888	$17,334,769	$1,265,422,362
2068	0.040	827,000	0.0140	839,000	42.83355	0.10587	0.21324	$423,224,248	$1,065,899	$2,146,900	$426,437,048	$16,960,141	**$1,282,382,503**
							CPVRR Total Cost =	**$1,244,550,363**	**$12,551,436**	**$25,280,704**	**$1,282,382,503**		

(14)	(15)
Year	Annual Change in Firm Point-to-Point Charges in OATT (%)
2020	---
2021	12.1%
2022	12.8%
2023	10.0%
2024	4.7%
2025	10.9%
2026	6.4%
2027	12.4%
2028	12.4%
2029	12.4%
High Value =	12.8%
Avg. Value =	10.4%
Low Value =	4.7%

Notes:

(1) For the "Reserved Capacity" value, the projected annual average hourly kW amount is used for purposes of this calculation although the maximum hourly flow is projected to be 850,000 kW in a number of hours. The smaller kW value was chosen to help ensure that the wheeling cost projection was conservative.

(2) In accordance with Duke Energy Florida's current Open Access Transmission Tariff (OATT), as of January 5, 2021, the Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factor in the DEF Zone as of January 5, 2021 is 1.40% for delivery at transmission voltages.

(3) 2020 Firm Point to Point charge is posted to Duke Energy Florida's OASIS site under file "Price Summary Sheet." The current projection for 2021-2029 Firm Point-to-Point rates was posted to Duke Energy Florida's OASIS site on December 29, 2020. New costs for each year are projected to begin June 1 of the new year. For 2030-on, the lowest projected annual escalation rate was used (See Column (15)).

(4) In accordance with Duke Energy Florida's current OATT, as of January 5, 2021, "Schedule 1" ancillary service charges for Scheduling, System Control and Dispatch Service must be purchased from the Transmission Provider or the Control Area operator. The current effective rate is posted to Duke Energy Florida's OASIS site.

(5) In accordance with Duke Energy Florida's current OATT, as of January 5, 2021, "Schedule 2" ancillary service charges for Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. In a wheeling scenario, Gulf Power would expect to purchase Schedule 2 ancillary service from the Transmission Provider.

FPL Stand-Alone Resource Plan Developed in the Current Step 2 Analyses

FPL Stand-Alone Resource Plan			
Retirements / Additions	**Year**	**Resource Additions**	**RM%**
1,043 MW Solar OUC PPA (100 MW) Indiantown PPA (330 MW)	2021	--	21.7
Manatee & Smaller Batteries(469 MW), DBEC (1,163 MW), Manatee 1&2 (1,618 MW), Scherer 4 (634 MW)	2022	1,043 MW Solar	20.1
---	2023	596 MW Solar 1 x 100 MW Battery	20.0
---	2024	3x0 CT (704 MW) 74.5 MW Solar	21.8
---	2025	521.5 MW Solar	21.6
---	2026	372.5 MW Solar	20.7
Broward South (4 MW)	2027	372.5 MW Solar	20.3
---	2028	745 MW Solar	20.0
---	2029	1,192 MW Solar 2 x 100 MW Battery	20.0
---	2030	1,192 MW Solar 4 x 100 MW Battery	20.1
	Total CPVRR =	**74,756**	

Notes:
CPVRR costs are in million $ and are discounted at 7.52% (FPL's most recent WACC) for the years 2020 thru 2068

Results of the Current Step 3 Analyses

FPL Area Retirements / Additions	Gulf Area Retirements / Additions	Year	FPL Area Resource Additions	Gulf Area Resource Additions	RM%
1,043 MW Solar OUC PPA (100 MW) Indiantown PPA (330 MW)	---	2021	--	--	*
Manatee & Smaller Batteries (469 MW), DBEC (1,163 MW), Manatee 1&2 (1,618 MW), Scherer 4 (634 MW)	NFRC Line Crist 4x0 CT (938 MW) 149 MW Solar	2022	447 MW Solar	--	25.5
---	Shell PPA (885 MW)	2023	372.5 MW Solar	372.5 MW Solar	21.6
---	Daniel 1&2 (502 MW)	2024	521.5 MW Solar	372.5 MW Solar	20.0
---	Crist 4 (75 MW) , Pea Ridge (12 MW)	2025	521.5 MW Solar	372.5 MW Solar	20.1
---	---	2026	894 MW Solar	74.5 MW Solar	20.0
Broward South (4 MW)	Crist 5 (75 MW)	2027	968.5 MW Solar	--	20.0
---	Lansing Smith A (32 MW)	2028	1,192 MW Solar	--	20.0
---	---	2029	1,043 MW Solar, 3 x 100 MW Battery	149 MW Solar	20.0
---	Perdido 1&2 (3 MW)	2030	968.5 MW Solar, 1 x 100 MW Battery	223.5 MW Solar 3 x 100 MW Battery	20.0

Step 3 CPVRR Cost =	**81,942**
FPL Stand-Alone + Gulf in Step 2 CPVRR =	**82,230**
CPVRR Cost Difference from Step 2 =	**(288)**

Notes:
CPVRR costs are in million $ and are discounted at 7.52% from 2020-2068 (Gulf Step 2 CPVRR was re-calculated with a 7.52% discount rate)
The recalculated CPVRR for Gulf in Step 2 is $7,474M (Not including NFRC line costs)
Cost of the NFRC line project was omitted from these CPVRR calculations because that cost is the same in Steps 2 and 3
* - Each system (FPL and Gulf) has its own separate reserve margin in 2021

Economic Analysis Results for the Planned 2022 and 2023 Solar Additions

Common to all Plans **Retirements / Additions**	**Year**	**No Solar after 2021**	**RM %**	**No Solar After 2022 & 2023 Solar Additions**	**RM %**
1,043 MW Solar, OUC PPA (100 MW), Indiantown PPA (330 MW)	2021	--	*	--	*
Manatee Batt. (469 MW), Crist 4x0 CT (938 MW), DBEC (1,163 MW), 149 MW Solar, NFRC Line, Manatee 1&2 (1,618 MW), Scherer 4 (634 MW)	2022	--	24.6	447 MW Solar	25.5
Shell PPA (885 MW)	2023	2 x 100 MW Battery	20.1	745 MW Solar	21.5
Daniel 1&2 (502 MW)	2024	3x0 CT (704 MW) 1 x 100 MW Battery	20.0	3x0 CT (704 MW)	21.0
Crist 4 (75 MW), Pea Ridge (12 MW)	2025	3x0 CT (704 MW)	21.1	3x0 CT (704 MW)	22.1
---	2026	3x1 CC (1,991 MW)	27.0	1 x 100 MW Battery	20.9
Crist 5 (75 MW), Broward South (4 MW)	2027	--	25.4	4 x 100 MW Battery	20.9
Lansing Smith A (32 MW)	2028	--	23.7	4 x 100 MW Battery	20.7
---	2029	--	21.6	4 x 100 MW Battery	20.0
Perdido 1&2 (3 MW)	2030	3 x 100 MW Battery	20.2	3x1 CC (1,991 MW)	24.5

	No Solar after 2021	No Solar After 2022 & 2023 Solar Additions
CPVRR Costs =	**$68,116**	**$67,718**
CPVRR Costs Difference from the No Solar after 2021 Plan =	**--**	**($397)**

Notes:
CPVRR costs are in million $ and are discounted at 7.52% from 2020-2053
* - Each system (FPL and Gulf) has its own separate reserve margin in 2021