BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210015-EI

Petition for rate increase
by Florida Power & Light
Company.
___________________________/

VOLUME 2
PAGES 263 - 500

PROCEEDINGS: HEARING

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

DATE: Monday, September 20, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of Jun K. Park was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JUN K. PARK

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Jun K. Park, and my business address is Florida Power & Light Company, 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" or the "Company") as the Manager of Load Forecasting.

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

A. I am responsible for the development of the customer, energy sales, and peak demand forecasts for FPL and Gulf Power ("Gulf").

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Alabama at Birmingham with a Bachelor of Science degree in Finance. I started my electric utility career in 1999 with Southern Company. Over the course of my career, I have held various positions with forecasting and analytical responsibilities, including forecasting wholesale energy prices, coordinating the development of price forecasts for fuel commodities and emissions allowances, and developing long-term energy and peak demand forecasts. I began leading Gulf's forecasting team in 2014. In January 2019, Gulf was acquired by NextEra Energy, Inc., which also owns FPL. In the third quarter of 2019, the load forecasting teams for FPL and Gulf were consolidated, and I became the manager of the consolidated team.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit JKP-1 Consolidated MFRs Sponsored or Co-sponsored by Jun K. Park
- Exhibit JKP-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-sponsored by Jun K. Park
- Exhibit JKP-3 Historical and Forecasted Consolidated FPL Customers
- Exhibit JKP-4 Historical and Forecasted Consolidated FPL Retail Delivered Sales
- Exhibit JKP-5 Forecasted Consolidated FPL Summer Peak Demands

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

A. Yes. Exhibit JKP-1 lists the consolidated MFRs that I am sponsoring and co-sponsoring.

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. Yes. Exhibit JKP-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. Have you previously provided testimony to the Florida Public Service Commission ("FPSC" or the "Commission")?

A. Yes. I provided direct testimony and sponsored MFRs as the load forecasting witness in Gulf's 2016 rate case, Docket No. 160186-EI.

Q. Please explain how you will be referring to FPL and Gulf in your testimony.

A. Gulf was acquired by FPL's parent company, NextEra Energy, Inc., on January 1, 2019. On January 1, 2021, FPL and Gulf were legally merged but maintained their status as separate ratemaking entities. In this proceeding, FPL is seeking to consolidate the FPL and Gulf rates into a single FPL rate-regulated entity effective January 1, 2022.

For purposes of my testimony, operations or time periods prior to January 1, 2019 (when Gulf Power Company was acquired by FPL's parent company, NextEra Energy, Inc.), "FPL" and "Gulf" will refer to their pre-acquisition status, when they were legally and operationally separate companies. For operations or time periods between January 1, 2019 and January 1, 2022, "FPL" and "Gulf" will refer to their status as separate ratemaking entities, recognizing that they were merged legally on January 1, 2021 and consolidation proceeded throughout this period. Finally, in discussing operations or time periods after January 1, 2022, most references will be only to "FPL" because Gulf will be consolidated into FPL. Therefore, unless otherwise noted, my testimony addresses requests for the consolidated Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and explain the customer, energy sales, and peak demand forecasts for the consolidated FPL system for the 2022 test year and 2023 subsequent year. My testimony also supports the inflation forecast used as part of the budgeting process and for computing the Commission's Operations and Maintenance ("O&M") Benchmark.

Q. Please summarize your testimony.

A. My testimony begins with an overview of the current economic conditions for the FPL and Gulf service areas, including how the unprecedented COVID-19 pandemic has affected the economies and customers in those areas, as well as the inflation forecast. Next, I provide an overview of the processes used to develop the consolidated forecasts for customers, energy sales, and peak demands and how these processes are fundamentally sound and consistent with the criteria used by the Commission in evaluating forecasts. The overview concludes with a brief discussion regarding the ways weather affects electricity usage and how FPL's normal weather method and use of weather-normalized historical data are consistent with industry best practices.

The next portion of my testimony discusses the customer forecasts along with the factors that drive customer growth. The consolidated annual average forecasts of total FPL customers are 5,717,534 and 5,785,456 for 2022 and 2023, respectively.

My testimony then discusses the energy sales forecasts and the methods, models, and inputs used to develop those forecasts. The consolidated total FPL retail delivered energy sales forecasts, including incremental Demand Side Management ("DSM"), are 122,083 GWh and 122,980 GWh in 2022 and 2023, respectively. These energy sales forecasts were developed using methods that have consistently provided accurate, reliable forecasts that are used for all regulatory and planning activities.

I then conclude with a discussion of the peak demand forecasts and how those forecasts were developed. The consolidated summer peak demand forecasts, including incremental DSM, are 27,205 MW and 27,661 MW for 2022 and 2023 respectively. These peak demands also reflect reductions in the consolidated system peak demands of 131 MW and 133 MW in 2022 and 2023 due to the benefits of peak demand diversity between the FPL and Gulf systems.

II. OVERVIEW

<u>Overview of Economic Conditions</u>

Q. Please describe the economic conditions in the FPL and Gulf service areas.

A. As of December 2020, FPL provides retail electric service to approximately 5.2 million customers in 35 counties in peninsular Florida, with an approximate population of 10.2 million. As of December 2020, Gulf provides retail electric service to approximately 473,000 customers in eight counties in Northwest Florida, with an approximate population of 878,000. As a consolidated company, FPL serves over 5.6 million retail customers in 43 counties. The combined service area includes roughly 11.1 million persons, or just over half of Florida's population.

The Great Recession, which lasted from December 2007 through June 2009, affected Florida's economy to a greater degree than other parts of the US. Between the first quarter of 2007 and the first quarter of 2010, Florida's total nonfarm employment fell 11.4 percent compared to the U.S.'s decline of 5.7 percent. Florida continued to see lingering impacts on its economy well beyond the end of the recession, with employment not recovering back to pre-recession levels until mid-2015. Starting in the first quarter of 2016 through the fourth quarter of 2019, Florida's economy gained momentum as employment grew cumulatively 8.7 percent while the U.S. employment grew 5.8 percent. However, growth halted in 2020 due to the COVID-19 pandemic and the shelter-in-place orders that were implemented to mitigate the virus's spread. This unprecedented shock to Florida's economy caused Florida's nonfarm employment to decline by 13.0 percent by the end of April. Over the next three months, Florida saw a slight rebound, with nonfarm employment growth of 4.5 percent during this period. Despite the rebound, nonfarm employment was still down 6.6 percent from the start of the year. Starting in August, the beginning point of the forecast, through the end of 2023, Florida's nonfarm employment is expected to grow at an average of 2.7 percent per year. The COVID-19 pandemic is also affecting Florida's population growth. Through 2023, population is projected to grow at an average annual rate of 1 percent, compared to the average annual growth rate of 1.4 percent for the period from 2016 through 2019.

Q. Has the COVID-19 pandemic affected energy usage?

A. Yes. The shelter-in-place orders and associated business closures resulted in significant reductions to commercial and industrial energy usage. However, those very same restrictions resulted in increases to residential energy usage as customers were spending more time at home. These impacts began to affect usage patterns beginning in March 2020 and continued through the third quarter of 2020. As the economy begins to recover from the impacts of the pandemic, usage patterns are expected to return to more normal patterns. The impacts of COVID-19 to date, and the projected recovery are captured in the forecasts.

Q. What is the basis for the economic projections?

A. The economic projections used for the customer, energy sales, and peak demand forecasts are from IHS Markit's August 2020 economic forecast, while the CPI projections are from IHS Markit's May 2020 economic forecast. IHS Markit is a recognized industry expert who has consistently provided objective and reliable economic projections.[1] FPL has relied on projections from IHS Markit for forecasting and budgeting purposes, including for FPL's 2012 and 2016 rate cases.

<u>Overview of Inflation Forecast</u>

Q. What inflation measure is used by FPL for budgeting purposes?

A. For its budgeting process, FPL uses IHS Markit's forecast of Consumer Price Index ("CPI") for all goods and services, which is also called overall CPI. This

[1] S&P Global and IHS Markit, two of the largest providers of financial data, announced in November 2020 an agreement to merge.

same CPI is also used when calculating the O&M Benchmarks. As previously discussed, the CPI projections are from IHS Markit's May 2020 economic forecasts. FPL's budgeting process begins earlier than the load forecasting process, and that is the reason why the budgeting process uses a different vintage of IHS Markit's economic forecast compared to the load forecasting process. This difference between the vintages for the CPI projections and the economic projections used for load forecasting is consistent with prior planning processes, including that used for FPL's 2016 rate case.

Q. What has been the historical trend for inflation?

A. Over the past 15 years, overall CPI has seen a cumulative increase of 28.1 percent. However, there are significant differences between the increase in overall CPI versus the subcategories that make up overall CPI. For example, over the same time period, food & beverage has increased by 35.8 percent, housing has increased by 33.4 percent, and medical care has increased by 54.2 percent.

Q. What is the forecast for inflation for 2022 and 2023?

A. Overall CPI is projected to increase by 1.7 percent and 0.8 percent in 2022 and 2023, respectively. The cumulative increase from 2021 through 2025 is projected to be 5.8 percent.

<u>Overview of Forecast Methodology</u>

Q. What is the objective of the load forecasting process?

A. The objective of FPL's load forecasting process is to produce reliable, unbiased forecasts of customers, energy sales, and system peak demands for the FPL system.

Q. Please explain how customers, sales and peak demands are defined.

A. Customer forecasts reflect the total number of active accounts served by FPL and include the impacts of new service installations combined with other factors, including changes in the number of inactive accounts. Retail delivered energy sales reflect the amount of energy provided to all retail customers served by FPL. Net Energy for Load ("NEL") is another measure of energy sales that takes into account the Megawatt Hours ("MWh") FPL provides to its retail and wholesale customers as well as system losses and energy used by company-owned facilities. Peak demands refer to the highest hourly integrated net energy for load over a given period of time.

Q. How were the consolidated customer, energy sales, and peak demand forecasts developed?

A. The consolidated customer, energy sales, and peak demand forecasts were all developed by combining the respective standalone forecasts for FPL and Gulf. The consolidated FPL forecasts for customers and energy sales are the simple sums of the respective standalone FPL and Gulf forecasts, while the consolidated FPL forecast of peak demands also takes into account the impacts of peak demand diversity, which is described later in my testimony.

Q. Please summarize how the customer, energy sales, and peak demand forecasts were developed.

A. The forecasts were developed using econometric models as the primary tool.

The various econometric models are statistically sound and include logically reasonable drivers obtained from leading industry experts. This approach provides accurate forecasts that are used for all business purposes. Detailed explanations for these models and their respective drivers, along with historical forecast accuracies, are provided later in my testimony.

Q. What statistical measures were used to evaluate the robustness of those forecast models?

A. Consistent with industry standard practices, FPL used adjusted R-squared, Mean Absolute Percent Error ("MAPE"), and the Durbin-Watson statistic to evaluate the robustness and accuracy of its forecast models. Additionally, the variables included in each model were also evaluated using the p-values for each variable. Below are descriptions of each statistical measure:

- The adjusted R-squared is a measure that quantifies how much of the variations in history are explained by the models. Adjusted R-squared values range from 0 to 100 percent, and higher values are preferred.
- MAPE is a measure of model residuals, which are the differences between the model's estimate for a historical period versus the actual historical value. The residuals are expressed on an absolute percentage basis and then averaged. MAPE values range from 0 percent and upward, and lower values are preferred.
- Durbin-Watson is a measure of serial correlation in the model's residuals, where serial correlation is when the residual in one period is highly correlated to residuals in prior periods. Ideally, model residuals

should have a random pattern. Durbin-Watson statistic values range from 0 to 4, and 2 is the preferred value.

- P-value is a measure which indicates the statistical significance of a variable to the model. P-values range from 0 to 100 percent, and lower values are preferred.

Q. Is this approach consistent with criteria used by the Commission in recent years to evaluate utilities' forecasts?

A. Yes. The Commission has evaluated utilities' forecasts based on the use of statistically sound forecasting methods and reasonable input assumptions (*e.g.*, Order Nos. PSC-16-0032-FOF-EI, PSC-14-0590-FOF-EI, PSC-13-0505-PAA-EI, PSC-12-0179-FOF-EI, PSC-12-0187-FOF-EI, PSC-09-0283-FOF-EI and PSC-08-0518-FOF-EI). The Commission has also considered whether a forecast is applied consistently; that is, whether a forecast used for one purpose, such as a rate filing, is the same forecast used for other purposes, such as generation planning (Order No. PSC-09-0283-FOF-EI). Lastly, the Commission has considered a utility's record of forecasting accuracy when evaluating forecasts (Order No. PSC-16-0032-FOF-EI).

Q. Did you develop customer, energy sales, and peak demand forecasts in support of FPL's request for approval of a Solar Base Rate Adjustment mechanism for years 2024 and 2025?

A. Yes. I developed the customer, energy sales, and peak demand forecasts for years 2021 through 2025 using actual data through August 2020 and IHS

Markit's August 2020 economic projections. The consolidated forecasts for years 2024 and 2025 are provided in exhibits JKP-3, JKP-4, and JKP-5.

Overview of Weather

Q. What is the role of weather in the load forecasting process?

A. Weather is a key driver for both energy sales and peak demands. Electricity sales will increase during periods of warm weather due to higher cooling load, which is additional electricity usage due to higher air conditioning usage. Energy sales will also increase during periods of cold weather due to higher heating load, which is additional electricity usage due to increased usage of electric heating. Peak demands are also affected by weather; however, for any given historical period, weather can have differing impacts on energy sales versus peak demands. This is because peak demands are the highest hourly energy usage, which means peak demands are affected by short-term weather patterns. Energy sales, on the other hand, are the cumulative energy used over a period of time, so energy sales are impacted by weather patterns that occur over longer periods of time.

Q. How are the impacts of weather captured in the load forecasting process?

A. Weather impacts are captured in the load forecasting process by first identifying the appropriate sources for weather data. Next, historical weather variables specific to each model are then calculated and included in the respective models. Finally, projected values for each weather variable, or "normal weather," are then calculated using the historical weather data.

Q. What are the sources for the weather data?

A. Consistent with industry standard practice, all historical weather data is based on weather observations from the National Oceanic and Atmospheric Administration ("NOAA"). The historical weather for the FPL service area is based on a system average temperature using the weather data from the Miami, West Palm Beach, Fort Myers, and Daytona Beach weather stations. The weightings for each weather station are based on the proportion of total FPL load served in the area represented by that weather station. The historical weather for the Gulf service area is based on the Pensacola weather station.

Q. What are the weather variables used in the forecasting process?

A. The energy sales forecast models use cooling degree hours and heating degree hours, while the peak demand models use peak day hourly temperatures or degree hours. Cooling degree hours are a cumulative measure of temperatures above the temperature threshold where cooling load increases, and heating degree hours are a cumulative measure of temperatures below the temperature threshold where heating load increases. Since energy sales are a cumulative measure of energy sales over a given time period, cooling degree hours and heating degree hours are appropriate weather variables for energy sales models. Unlike energy sales, peak demand is the highest hourly integrated demand during a given time period; therefore, peak day hourly temperatures or degree hours are the appropriate weather variables for peak demand models. Detailed descriptions for each of the weather variables are provided later in my testimony.

Q. How is normal weather calculated?

A. Normal weather is calculated as the average of the most recent 20 years of historical weather.

Q. Is 20-year normal weather consistent with standard industry practice?

A. Yes. Although there may be some exceptions, the 20-year normal weather is a widely used industry practice. FPL and Gulf, along with Tampa Electric Company, have relied on 20-year normal weather for forecasting and weather normalization. The use of 20-year normal weather is appropriate because it provides stability to the weather assumptions, which in turn provides greater stability to the load forecasts, and this stability is especially important given the inherent volatility of weather.

Q. What is weather normalization?

A. Weather normalization refers to the process of adjusting actual energy sales or peak demands to reflect average, or normal weather. For example, the weather in the FPL service area was warmer than normal during 2019 and this warmer than normal weather resulted in higher energy sales for FPL during 2019. The first step in weather normalizing 2019 energy sales is to compare 2019 actual weather versus normal weather. The energy sales impact of the difference is then quantified using energy sales models. Finally, the impacts of weather are removed from 2019 actual energy sales to arrive at 2019 weather normalized sales.

Q. Why is it necessary to use weather-normalized historical data?

A. The use of weather-normalized historical data is necessary when calculating growth rates. If the growth rates are calculated using historical data that is not weather-normalized, the resulting calculated growth rates will be affected by the variability of weather. Weather normalizing historical data removes the variability of weather and the resulting growth rates reflect the true underlying growth trends. Similarly, weather-normalized historical data is also necessary when determining the accuracy of a forecast.

Q. Is the use of weather-normalized data an industry best practice?

A. Yes. It is an industry best practice to use weather-normalized data when calculating growth rates and determining forecast accuracy. For example, electric utilities in Florida have relied on weather-normalized sales variances in their rate filings consistent with the Commission's policy that rates be based on weather-normalized sales (Order No. PSC-11-0103-FOF-EI).

III. CUSTOMER FORECAST

Customer Forecast Overview

Q. What is the objective of the customer forecast process?

A. The objective of the customer forecast process is to produce reliable, unbiased forecasts for the number of total customers and retail customers by revenue class, where a customer is defined as an active service account.

Q. What are the forecasts for total customers for 2022 and 2023?

A. Table JKP-1 summarizes the total customer forecasts for 2022 and 2023.

Table JKP-1		
Total Customer Forecasts		
	2022	2023
Standalone FPL	5,238,591	5,301,693
Standalone Gulf	478,943	483,764
Consolidated FPL	5,717,534	5,785,456

Additionally, Exhibit JKP-3 shows the consolidated forecasts for years 2024 and 2025, along with historical customer data beginning 2010. The historical customer data was developed by summing the FPL and Gulf customers.

Q. What are the drivers of the customer forecast?

A. The primary driver of the customer forecast is the number of households, where a household is a separate living arrangement for one or more persons. Households are directly related to residential customers, and residential customers make up the majority of total customers. Other factors that drive the customer forecast are retail sales activity and housing starts, which is a function of new construction activity. Retail sales activity drives the commercial customer forecast because changes in retail sales activity affect the number of commercial businesses. Housing starts drive the industrial customer forecast primarily associated with new construction activity.

Q. Have any other factors influenced customer growth in recent years?

A. Yes. One factor specific to FPL was initiated in the second half of 2013. FPL began using Automated Metering Infrastructure ("AMI" or "smart meter") technology to reduce the number of unknown usage ("UKU") premises. A UKU premise is a location where electricity is being consumed without an active customer account. If a UKU premise was identified, the occupants of the premise would have to open an account or have the electric service terminated.

This program was implemented beginning in the second half of 2013 and has resulted in an increase in the number of active accounts.

Another factor that influenced Gulf's recent customer growth was Hurricane Michael, which struck the eastern portion of the Gulf service area in October 2018. The Category 5 storm devastated the Panama City area, and significant numbers of premises were temporarily or permanently destroyed, resulting in substantial customer losses.

Recessions also affect customer growth. For example, the Great Recession, which lasted from December 2007 through June 2009, caused severe slowdowns in both FPL's and Gulf's customer growth rates for several years after the end of the recession.

Finally, customer growth is affected by acquisitions. For example, the electric utility customers previously served by the City of Vero Beach became FPL customers in late 2018.

Q. How was the consolidated customer forecast developed?

A. The consolidated customer forecast was developed using a "bottom-up" approach, where the total customer forecast is the sum of the customer forecasts for the individual revenue classes. The revenue classes included in the total forecast are residential, commercial, industrial, street & highway lighting, railroads & railways, other, and wholesale requirements. The consolidated revenue class customer forecasts were developed by summing the respective standalone revenue class customer forecasts for FPL and Gulf. This approach is consistent with the methodology used to develop the customer forecast provided in the combined 2020-2029 Ten Year Site Plan for FPL and Gulf (hereinafter, the "FPL/Gulf 2020 TYSP") that was approved in the Commission's Review of the 2020 Ten-Year Site Plans of Florida's Electric Utilities, issued on October 6, 2020. The consolidated customer forecasts for 2022 and 2023 are shown in Table JKP-1 and Table JKP-14. Additionally, Exhibit JKP-3 shows the consolidated customer forecasts for years 2024 and 2025, along with historical customer data beginning 2010. The historical customer data was developed by summing the FPL and Gulf customers.

Q. Have there been any changes to the customer forecast methodology since the prior rate cases for either FPL or Gulf?

A. Yes, certain changes described below were made beginning with the forecasts presented in the FPL/Gulf 2020 TYSP. These changes are reasonable and ensure that the standalone FPL and Gulf customer forecasts employ the same methodology.

In its 2016 rate case, FPL used a "top-down" approach to develop its customer forecast, where the number of total customers was forecasted using a regression model. The customer forecasts for the residential and commercial revenue class were then adjusted by the difference between the sum of the revenue class forecasts and the total customer forecast. The current customer forecast is based on a “bottom-up” approach used by Gulf, which is described in more detail later in my testimony. FPL’s adoption of the bottom-up approach allows the customer forecasts to reflect better differences in growth rates between the customer classes.

In its 2016 rate case, residential customers for Gulf were forecasted based on inputs from Gulf’s field marketing managers for the first two forecast years and then tied to household growth for subsequent years. Commercial customers for Gulf were forecasted based on inputs from Gulf’s field marketing managers for the first forecast year and then tied to residential customer growth for subsequent years. Industrial customers for Gulf were forecasted based on inputs from Gulf’s field marketing managers for the first forecast year and then grown based on historical trends. The customer forecast methodology used in this proceeding adopts FPL’s approach and relies on multiple linear regression (or “regression”) models or exponential smoothing (or “exponential”) models for the entire forecast period. Gulf’s adoption of models for forecasting customers improves productivity while still providing accurate forecasts.

Q. Does the current method provide accurate customer forecasts?

A. Yes. The accuracy of the current method is demonstrated by comparing the 2020 actuals with the forecasts developed for the FPL/Gulf 2020 TYSP using the same method, which were within 0.4 and 0.3 percent for FPL and Gulf, respectively.

<u>Residential Customer Forecasts</u>

Q. How was the consolidated residential customer forecast developed?

A. The consolidated residential customer forecast was developed by summing the standalone FPL and Gulf residential customer forecasts. These standalone forecasts were developed using two regression models, one for each of the companies, and the primary driver for each model was the number of households.

Q. What is the relationship between the number of households and population?

A. The number of households is directly related to population and the only differentiating factor is the number of persons per household. If the number of persons per household is constant, then household growth is the same as population growth. But if the number of persons per household is decreasing, then the household growth will be higher than population growth. A slight decrease in the number of persons per household is projected over the next few years as the economy is projected to begin to recover, and the result is that the number of households are projected to grow slightly faster than population growth.

Q. What was the source of the household growth projections?

A. The household growth projections used in the models were from the August 2020 economic projections provided by IHS Markit. Both FPL and Gulf have relied on economic projections from IHS Markit for a number of years, including the forecasts provided in the FPL/Gulf 2020 TYSP.

Q. Do the residential models rely on additional variables beyond households?

A. Yes. Along with households, the standalone FPL residential customer forecast regression model also included two lagged dependent variables, a variable for unknown usage premises (previously described in my testimony) and binary terms. The other variables included in the standalone Gulf residential customer forecast were a lagged dependent variable, a binary term, and two moving averages to address serial correlation in model residuals. A detailed list of all variables, including descriptions, is provided in MFR F-5.

Q. Are the residential models statistically sound?

A. Yes. Table JKP-2 summarizes the adjusted R-squared ("R^2"), MAPE, and Durbin-Watson ("D-W") statistics for the residential models.

Table JKP-2			
Residential Customer Models			
	R^2	MAPE	D-W
Standalone FPL	99.99%	0.05%	2.00
Standalone Gulf	99.94%	0.07%	1.87

These statistics indicate both models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

<u>**Commercial Customer Forecasts**</u>

Q. How was the consolidated commercial customer forecast developed?

A. Similar to the residential customer forecast, the consolidated commercial customer forecast was developed by summing the standalone FPL and Gulf commercial customer forecasts. These standalone forecasts were developed using two exponential models and two regression models.

Q. Please describe the commercial customer exponential models.

A. One exponential model was used to forecast large commercial customers (customers on demand rates of 500 kW and above) for FPL, and another exponential model was used to forecast large commercial customers (customers 25 kW or greater) for Gulf.

Q. Please describe the commercial customer regression models.

A. One commercial regression model was used to forecast small/medium commercial customers (customers on energy only rates and demand rates less than 500 kW) for FPL, and another regression model was used to forecast small commercial customers (customers less than 25 kW) for Gulf. A detailed list of all model variables, including descriptions, is provided in MFR F-5.

Q. Are these commercial customer models statistically sound?

A. Yes. The statistics for the commercial customer models are shown in Table JKP-3.

Table JKP-3
Commercial Customer Models

		R^2	MAPE	D-W
Standalone FPL	Large	98.28%	0.34%	1.91
	Small/Medium	99.99%	0.04%	1.89
Standalone Gulf	Large	96.30%	0.15%	1.89
	Small	99.80%	0.26%	1.91

These statistical measures indicate the commercial customer models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

Industrial Customer Forecasts

Q. How was the consolidated industrial customer forecast developed?

A. The consolidated industrial customer forecast was also developed by summing the standalone FPL and Gulf industrial customer forecasts. These standalone forecasts were developed using three exponential models and one regression model.

Q. Please describe the industrial customer exponential models.

A. One exponential model was used to forecast medium industrial customers (customers on demand rates less than 500 kW) for FPL, another exponential model was used to forecast large industrial customers (customers on demand rates 500 kW and above) for FPL, and a final exponential model was to forecast industrial customers for Gulf.

Q. Please describe the industrial customer regression model.

A. A regression model was used to forecast small industrial customers (customers on energy only rates) for FPL. The model variables were housing starts, lagged dependent variables, and historical binary terms. A detailed list of all model variables, including descriptions, is provided in MFR F-5.

Q. Are the industrial customer models statistically sound?

A. Yes. The statistics for the industrial customer models are shown in Table JKP-4.

Table JKP-4				
Industrial Customer Models				
		R^2	MAPE	D-W
Standalone FPL	Large	88.20%	0.75%	1.98
	Medium	94.96%	0.70%	2.00
	Small	99.78%	0.82%	1.96
Standalone Gulf	Industrial	95.96%	0.63%	2.00

These statistical measures indicate the standalone FPL and Gulf industrial models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

Customer Forecasts for All Other Revenue Classes

Q. How were the consolidated forecasts for all other retail revenue classes developed?

A. The other retail revenue classes are street & highway lighting, railroads & railways, and other. The street & highway lighting class forecasts for both standalone companies were provided by FPL's Rate Development and Lighting teams regarding expected growth trends. The FPL customer forecasts for the railroads & railways and other revenue classes were developed using exponential models. Gulf does not have customers in the railroads & railways and other revenue classes.

New Service Accounts Forecast

Q. What is a new service account ("NSA"), and how is the NSA forecast used in this rate proceeding?

A. A NSA is when service is established for the first time at a new premise. The

NSA forecast is used by various departments, including Power Delivery and Financial Forecasting, as one of the indicators of future growth.

Q. What are the NSA forecasts for 2022 and 2023?

A. NSAs for 2022 and 2023 are forecasted to be 86,638 and 91,480, respectively. Cumulative NSA growth from 2019 through 2023 is forecasted to be 425,497.

Q. How was the consolidated NSA forecast developed?

A. The consolidated NSA forecast was developed by summing the standalone FPL and Gulf NSA forecasts. The standalone forecasts were developed using three regression models.

The standalone FPL residential NSA regression model included variables for income, housing starts, a binary term, and two autoregressive terms. The standalone FPL commercial NSA regression model included variables for housing starts, a lagged dependent variable, binary terms, and two autoregressive terms.

The standalone Gulf residential NSA regression model included variables for housing starts and an autoregressive term. The standalone Gulf commercial NSA forecast was developed by multiplying the Gulf residential NSA forecast by the FPL commercial versus residential NSA ratio.

Q. Are the NSA models statistically sound?

A. Yes. The statistics for the NSA models are shown in Table JKP-5.

Table JKP-5				
NSA Models				
		R^2	MAPE	D-W
Standalone FPL	Residential	92.67%	12.96%	2.09
	Commercial	91.94%	10.75%	2.00
Standalone Gulf	Residential	79.96%	21.37%	2.37

These statistical measures indicate the NSA models display excellent goodness of fit, have acceptable model residuals, and have little serial correlation.

IV. ENERGY SALES FORECAST

Energy Sales Forecast Overview

Q. What is the objective of the energy sales forecast process?

A. The objective of the energy sales forecast process is to produce reliable, unbiased forecasts of all components of NEL. The components of NEL are retail delivered energy sales, wholesale delivered energy sales, and total losses including company use.

Q. What are the drivers of the NEL forecast?

A. The primary driver of the NEL forecast is the retail energy sales forecast because retail energy is the largest component of NEL. However, changes in wholesale requirements sales contracts can also affect the NEL forecast. Table JKP-6 summarizes the components that make up the consolidated NEL.

Table JKP-6		
Net Energy for Load Build Up		
Annual GWh	**2022**	**2023**
Retail Billed Sales	122,097	122,937
+ Retail Unbilled Sales	-13	44
= Retail Delivered Sales	122,083	122,980
+ Wholesale Delivered Sales	7,209	7,272
+ Losses	6,287	6,334
= NEL	135,579	136,586

Q. What are the consolidated retail energy sales forecasts for 2022 and 2023?

A. Table JKP-7 summarizes the retail energy sales forecasts by revenue class.

Table JKP-7		
Retail Billed and Unbilled Sales Forecasts		
Annual GWh	**2022**	**2023**
Residential Billed	65,361	65,602
+ Commercial Billed	51,411	51,887
+ Industrial Billed	4,858	5,006
+ Street & Highway Billed	362	337
+ Railroad & Railways Billed	85	85
+ Other Billed	20	20
= Retail Billed Sales	122,097	122,937
+ Retail Unbilled Sales	-13	44
= Retail Delivered Sales	122,083	122,980

Exhibit JKP-4 shows the consolidated retail delivered energy sales forecasts for years 2024 and 2025, along with weather-normalized historical energy sales data beginning 2010. The historical weather-normalized energy sales data was developed by summing the FPL and Gulf weather-normalized energy sales.

Q. How was the retail energy sales forecast developed?

A. Similar to the customer forecast, the retail energy sales forecast was developed using a “bottom-up” approach, where the total retail energy sales forecast was the sum of the energy sales forecasts for each of the retail revenue classes. The revenue class forecasts were primarily developed using econometric models.

Where appropriate, the model results were then adjusted for factors that were not otherwise captured in the respective model histories.

Q. What are the retail revenue classes used in the consolidated energy sales forecast?

A. The retail revenue classes are residential, commercial, industrial, street and highway lighting, railroads & railways, and other. FPL has customers in all classes, while Gulf has customers in all classes except railroads & railways and other.

Q. What factors drive the econometric models and model adjustments?

A. The econometric models are driven primarily by a combination of weather, economic conditions, electricity prices, and changes in equipment efficiencies. Some of the model results were adjusted for the impacts of new technologies such as electric vehicles, increased adoption of private solar generation, and Company-sponsored programs such as those included in the Companies' Commission-approved DSM plans. Detailed descriptions of the models and any adjustments are provided later in my testimony.

Q. Have there been any changes to the retail energy sales forecast methodology since the prior rate cases for either FPL or Gulf?

A. Yes, changes described below were made beginning with the forecasts presented in the FPL/Gulf 2020 TYSP. These changes are reasonable and ensure that the standalone FPL and Gulf energy sales forecast now rely on the same methodology.

In its 2016 rate case, FPL employed a "top-down" approach where forecasts were developed for NEL, retail energy sales, wholesale energy sales, and losses. The retail energy sales forecast was then adjusted to ensure the sum of the retail, wholesale, and losses forecasts matched the NEL forecast. The current forecast is based on Gulf's "bottom-up" approach where NEL is the sum of the forecasts for retail energy sales, wholesale energy sales, and losses. FPL's adoption of the bottom-up approach allows the energy sales forecast to reflect better the differences in energy usage patterns between the customer classes, such as the previously discussed usage changes which occurred as a result of the COVID-19 pandemic.

In its 2016 rate case, the industrial sales forecast for Gulf was primarily driven by inputs from Gulf's account representatives who identified expected load changes for the largest industrial customers. The current industrial sales forecast adopts FPL's approach and is based on the result of multiplying the forecast of customers by the forecast of energy usage per customer. Gulf's adoption of models for industrial usage improves productivity while still providing accurate forecasts.

Q. Does the current method provide accurate retail energy sales forecasts?

A. Yes. The accuracy of the current method is demonstrated by comparing the 2020 weather-normalized retail energy sales with the forecasts developed for the FPL/Gulf 2020 TYSP using the same method, which were within 1.5 and 1.2 percent for FPL and Gulf, respectively.

<u>Residential Energy Sales Forecast</u>

Q. How was the consolidated residential energy sales forecast developed?

A. The consolidated residential energy sales forecast was developed by summing the standalone FPL and Gulf residential sales forecasts. These sales forecasts were developed by multiplying the residential customer forecasts by the residential energy usage forecasts and average billing days. The residential usage forecasts were developed using two regression models, one for each company. The average billing days were developed using historical averages.

Q. What variables are included in the residential usage models?

A. The standalone FPL model incudes variables for cooling degree hours, heating degree hours, income, electricity prices, energy efficiency codes and standards, binary terms, and an autoregressive term. The standalone Gulf model includes variables for cooling degree hours, heating degree hours, electricity prices, energy efficiency codes and standards, binary terms, and an autoregressive term. A detailed list of all model variables, including descriptions, is provided in MFR F-5.

Q. Are these models statistically sound?

A. Yes. The statistics for the residential usage models are shown in Table JKP-8.

Table JKP-8			
Residential Usage Models			
	R^2	**MAPE**	**D-W**
Standalone FPL	99.09%	1.36%	1.91
Standalone Gulf	98.91%	1.72%	1.90

These statistical measures indicate both models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

Q. Were any adjustments applied to the residential energy sales forecasts?

A. Yes. The residential energy sales forecasts were adjusted for unbilled energy, Commission-approved DSM plans, impacts from private solar, and impacts from plug-in electric vehicles.

The unbilled energy adjustments were needed to adjust billed energies to calendar or delivered energies. The residential models were developed using billed historical energy data that reflects staggered usage across both the current and prior months. The unbilled adjustment corrects for the staggered usage and results in delivered energy that aligns with a calendar month.

The DSM adjustments capture the incremental DSM energy savings that are above and beyond those already reflected in the historical data for FPL and Gulf. These impacts are consistent with the 2020-2029 DSM goals established by the Commission in Order No. PSC-2019-0509-FOF-EG and incorporate actuals through July 2020.

The private solar adjustment captures the load impacts from private solar generation located behind customers' meters that are not otherwise reflected in the historical data. The private solar adjustment starts with the forecast of installed solar capacity for the state of Florida provided by external consultant Wood Mackenzie. Next, the shares of solar capacity in the FPL and Gulf service areas were estimated using the historical proportion of solar capacity within the service areas. Finally, the energy impacts are calculated using solar profiles from the National Renewable Energy Laboratory's PVWatts calculator.

The electric vehicle ("EV") adjustments capture the load impacts from EV charging that were not otherwise reflected in the historical data for FPL and Gulf. The EV adjustment starts with the Bloomberg New Energy Forecast of plug-in EVs for the U.S. Next, the share of EVs in the FPL and Gulf service areas were estimated using Florida Department of Motor Vehicles data for the counties in the service areas. Finally, the energy impacts are calculated using an estimate of kilowatt-hours per vehicle.

<u>**Commercial Energy Sales Forecast**</u>

Q. How was the consolidated commercial energy sales forecast developed?

A. The consolidated commercial energy sales forecast was developed by summing the standalone FPL and Gulf commercial sales forecasts. These standalone sales forecasts were developed by multiplying the commercial customer forecasts by the commercial energy usage forecasts and average billing days. The commercial usage forecasts were developed using four regression models. The two FPL commercial usage models were for small/medium commercial (energy only rates and demand rates less than 500 kW) and large commercial (demand rates 500 kW and above). The two Gulf commercial usage models were for small commercial (rates less than 25 kW) and large commercial (rates

25 kW or greater). The commercial class segments are consistent between the customer forecasts and energy usage forecasts.

Q. What variables are included in the commercial usage models?

A. The standalone FPL small/medium commercial usage model included variables for cooling degree hours, electricity prices, energy efficiency codes and standards, employment, binary terms, and an autoregressive term. The standalone FPL large commercial usage model included variables for cooling degree hours, electricity price, employment, binary terms, and an autoregressive term.

The standalone Gulf small commercial usage model included variables for cooling degree hours, heating degree hours, electricity prices, energy efficiency codes and standards, binary terms, and an autoregressive term. The standalone Gulf large commercial usage model included variables for cooling degree hours, heating degree hours, electricity prices, energy efficiency codes and standards, binary terms, and an autoregressive term.

A detailed list of all model variables, including descriptions, is provided in MFR F-5.

Q. Are these commercial usage models statistically sound?

A. Yes. The commercial usage models' statistics are shown in Table JKP-9.

Table JKP-9				
Commercial Usage Models				
		R^2	MAPE	D-W
Standalone FPL	Large	91.95%	1.49%	1.94
	Small/Medium	98.29%	0.95%	1.78
Standalone Gulf	Large	98.43%	1.32%	2.15
	Small	98.14%	1.92%	2.21

These statistical measures indicate the standalone FPL and Gulf models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

Q. Were any adjustments applied to the commercial energy sales forecast adjustments?

A. Yes. The commercial energy sales forecasts were adjusted for unbilled energy, Commission-approved DSM plans, impacts from private solar, and impacts from economic development tariffs. The adjustments for unbilled energy, Commission-approved DSM plans, and impacts from private solar were described previously in my testimony. An adjustment for economic development tariffs was needed in order to capture the additional load to standalone FPL associated with economic development tariffs. These tariffs provide discounts to customers who are adding new or incremental load, which would not otherwise be reflected in the historical data. The additional load impact was provided by FPL's Rate Development and Economic Development teams.

<u>Industrial Energy Sales Forecast</u>

Q. How was the consolidated industrial energy sales forecast developed?

A. The consolidated industrial energy sales forecast was developed by summing the standalone FPL and Gulf industrial energy sales forecasts. The standalone FPL large industrial sales forecast was developed by multiplying the industrial customer forecasts by the industrial energy usage forecasts; the other standalone industrial sales forecasts were developed by multiplying the customer forecasts by the energy usage forecasts and average billing days. The industrial usage forecasts were developed using one regression model and three exponential models.

Q. Please describe the industrial usage models.

A. The standalone FPL industrial usage was forecasted using a regression model for small industrial customers, an exponential model for medium industrial customers, and an exponential model for large industrial customers. The standalone FPL small industrial regression model included variables for cooling degree hours, a binary term, and an autoregressive term. The standalone Gulf industrial usage was forecasted using an exponential model. A detailed list of all regression model variables, including descriptions, is provided in MFR F-5.

Q. Are the industrial usage models statistically sound?

A. Yes. The statistics for the industrial usage models are shown in Table JKP-10.

Table JKP-10				
Industrial Usage Models				
		R^2	MAPE	D-W
Standalone FPL	Large	56.55%	4.39%	2.04
	Medium	75.33%	1.67%	2.24
	Small	92.16%	3.40%	2.10
Standalone Gulf	Industrial	81.20%	4.58%	2.00

These statistical measures indicate the models generally display acceptable goodness of fit, have minimal model residuals, and have insignificant serial correlation. Compared to the residential and commercial classes, the medium and large industrial class customer usage is less homogenous across the class and more sensitive to unpredictable events due to the small number of customers in the class. These factors result in greater volatility in the historical data. The R-squared value describes the relationship between the movements of the included independent variables compared to the dependent variable. The R-squared value alone is not indicative of the overall model's reliability or ability to provide accurate forecasts; instead, it is simply an indication of how well the included independent variables capture the changes in the dependent variable. If the dependent variable is affected by factors that are not observable or not readily obtainable, such as unexpected industrial customer outages, the resulting model's R-squared value would be lower.

<u>**Energy Sales Forecasts for All Other Retail Revenue Classes**</u>

Q. How were the consolidated forecasts for the remaining retail revenue classes developed?

A. The street & highway lighting energy forecasts for both standalone companies were provided by FPL's Rate Development and Lighting teams regarding expected growth trends. The FPL railroads & railways and other energy forecasts were developed by multiplying the forecasted number of customers by the forecasted energy usage. The railroads & railways energy usage forecast was developed using a regression model which included binary terms and an autoregression term. A detailed list of all variables in the regression model is provided in MFR F-5. The other energy usage forecast was developed using an exponential model. Gulf does not have customers in the railroads & railways and other revenue classes.

<u>Energy Forecasts for Territorial Wholesale Sales, Losses, and NEL</u>

Q. How were the energy forecasts for territorial wholesale sales, losses, and NEL developed?

A. The development of the wholesale energy sales forecasts began with information regarding which wholesale contracts are known. The energies associated with those contracts were then forecasted using a combination of contract terms, energy sales forecasts provided by the counterparty, and econometric modeling. The forecast of energy losses was developed using a historical loss factor. The forecast of NEL was developed by adding together the energy forecasts for retail sales, wholesale sales, and losses. Table JKP-6, shown earlier in my testimony, summarizes the components that add up to the NEL forecast.

V. PEAK DEMAND FORECAST

Peak Demand Forecast Overview

Q. What is the objective of the peak demand forecast process?

A. The objective of the peak demand forecast process is to provide reliable, unbiased projections of monthly system peak demands, where the system peak demand is the highest hourly demand by month.

Q. How were the peak demand forecasts developed?

A. The consolidated peak demand forecasts was developed by taking the highest hourly value in each month for the consolidated hourly load forecast. The consolidated FPL hourly load forecast was developed by combining the standalone FPL and Gulf hourly load forecasts. The standalone hourly forecasts were developed by first forecasting the monthly peak demands using econometric models and monthly ratios. Where appropriate, the model results were then adjusted for factors not otherwise reflected in model history. The adjusted monthly peak demands were then combined with the monthly NEL forecasts and historical hourly loadshapes to arrive at forecasted hourly loads. The monthly peak demands for the consolidated system were the highest hourly load in each month.

Q. Why was it necessary to combine the standalone FPL and Gulf hourly load forecasts as opposed to simply adding together the peak demand forecasts?

A. Simply adding the peak demand forecasts for the standalone companies will not capture the impacts of load diversity. Differences in hourly load profiles for

FPL and Gulf result in peak demands occurring in different hours for the standalone companies. These differences mean the consolidated peak demand will be lower than the sum of the standalone peak demand values. When the hourly load forecasts for the standalone companies are combined, the resulting highest hourly load for the consolidated system will capture the impacts of the differences in hourly load profiles.

Q. What is peak demand diversity?

A. Peak demand diversity is when the peak demand for a combined system is less than the sum of the peak demands for the individual components that make up the combined system. This reduction in the combined system peak demand is due to differences in the hourly load profiles, and these differences are typically due to different customer compositions, weather patterns, and time zones.

Q. What are the peak demand forecasts for 2022 and 2023?

A. The monthly peak demand forecasts, including incremental DSM, are provided in MFR E-18. The summer and winter peak demand forecasts for 2022 and 2023 are summarized in tables JKP-11 and JKP-12, along with the standalone peak demand forecasts and the peak demand reductions to the consolidated peak demands due to peak demand diversity. Finally, Exhibit JKP-5 provides the consolidated summer peak demand forecasts for years 2021 through 2025.

Table JKP-11

Summer Peak Demand Forecasts

MW	2022	2023
Standalone FPL	24,908	25,353
Standalone Gulf	2,428	2,441
Consolidated FPL	27,205	27,661
Diversity Benefit	-131	-133

Table JKP-12

Winter Peak Demand Forecasts

MW	2022	2023
Standalone FPL	20,289	20,672
Standalone Gulf	2,413	2,423
Consolidated FPL	22,436	22,826
Diversity Benefit	-267	-270

Q. When are the summer peak demands expected to occur?

A. The consolidated summer peak is expected to occur in August between 4-5 PM Eastern time zone. The consolidated summer peak is driven by both the FPL summer peak, which is also expected to occur in August between 4-5 PM Eastern, and the Gulf summer peak, which is expected to occur in July between the hours of 4-5 PM Eastern. The summer peak demand diversity for the consolidated system is due to the differences in the timing of the summer peaks for the standalone companies.

Q. When are the winter peak demands expected to occur?

A. The consolidated winter peak is expected to occur in January between 7-8 AM Eastern time zone. Like the consolidated summer peak, the winter peak is also driven by both the FPL winter peak, which is also expected to occur in January between 7-8 AM Eastern, and the Gulf winter peak, which is expected to occur in January between the hours of 7-8 AM Eastern. Although both standalone companies are expected to peak during the same month and hour, the day of the peaks are expected to be different because historically, the two standalone systems rarely experience their winter peaks during the same day. Because of this historical relationship, the consolidated winter peak demand does reflect diversity benefits.

Q. Has there been a change to the peak demand forecast methodology since the prior rate cases for FPL and Gulf?

A. The peak demand forecast methodology is the same methodology used in FPL's 2016 rate case. This methodology is a change from the peak demand forecast methodology used by Gulf in its 2016 rate case. In its 2016 rate case, Gulf's peak demands were forecasted using a Southern Company proprietary model that developed individual class-level hourly loadshapes, which were then combined to arrive at the total system hourly. The monthly peak demands were the highest hourly load within each month. Beginning with the forecasts presented in the FPL/Gulf 2020 TYSP, the current standalone Gulf forecast method relies on regression models and is consistent with the FPL forecast method.

Q. Does the current method provide accurate peak demand forecasts?

A. Yes. The accuracy of the current method is demonstrated by comparing the 2020 weather-normalized summer peak demands with the forecasts developed for the FPL/Gulf 2020 TYSP using the same method, which were within 1.3 and 0.6 percent for FPL and Gulf, respectively.

<u>**Standalone Monthly Peak Demand Forecasts**</u>

Q. What is the method for developing the standalone monthly peak demand forecasts for FPL and Gulf?

A. The development of the standalone monthly peak demand forecasts begins with forecasting summer peak demands and winter peak demands using peak demand per customer regression models. Next, the model results were multiplied by the number of customers and then adjusted for factors that were not otherwise captured in the respective model histories. Finally, the monthly peak demands for the other months are forecasted based on the historical relationships between the peaks in those months and the annual summer peak.

The standalone FPL summer peak demand forecast was developed using a regression model with variables for weather, employment, energy efficiency codes and standards, a binary term, and an autoregressive term. The winter peak demand forecast was developed using a regression model with variables for weather, employment, and historical binary terms. A detailed list of all model variables, including descriptions, is provided in MFR F-5. The historical relationships between the annual summer peak and the peaks for all other months excluding January were developed using the average of the past 20 years. Adjustments for wholesale requirements, private solar, plug-in electric vehicles, and the impact of economic development tariffs were made to the model results to arrive at the final monthly peak demand forecasts.

The standalone Gulf summer peak demand forecast was developed using a regression model with variables for weather, income, energy efficiency codes and standards, and a moving average term. The winter peak demand forecast was developed using a regression model with variables for weather, number of customers, energy efficiency codes and standards, a binary term, and two autoregressive terms. A detailed list of all model variables, including descriptions, is provided in MFR F-5. The historical relationships between the annual summer peak and the peaks for all other months excluding January were developed using the average of the past 20 years. Adjustments for private solar and plug-in electric vehicles were made to the model results to arrive at the final monthly peak demand forecasts.

Q. Are these summer and winter peak demand models statistically sound?

A. Yes. The statistics for the summer and winter peak demand models are shown in Table JKP-13.

Table JKP-13 Peak Demand Models				
		R^2	MAPE	D-W
Standalone FPL	Summer	88.43%	1.38%	1.89
	Winter	85.31%	4.08%	2.04
Standalone Gulf	Summer	95.50%	0.89%	1.58
	Winter	96.53%	1.52%	2.06

These statistics indicate both models display excellent goodness of fit, have minimal model residuals, and have insignificant serial correlation.

Q. Please describe the peak demand adjustments.

A. Both standalone FPL and Gulf monthly peak demand forecasts were adjusted for the impacts of incremental DSM, private solar, and plug-in electric vehicles. The adjustments for incremental DSM were based on the DSM plans which were approved by the Commission in Order No. PSC-2020-0291-CO-EG. The private solar and plug-in electric vehicle adjustments were calculated by FPL's Development team. Additionally, the FPL monthly peak demand forecasts were adjusted for wholesale requirements contracts and impacts from economic development tariffs.

Hourly Load Forecasts

Q. How were the hourly load forecasts developed?

A. The consolidated hourly load forecast was developed by adding together the standalone FPL and Gulf hourly load forecasts. The standalone hourly load forecasts were developed by applying the standalone FPL and Gulf respective forecasted monthly peak demands and NELs to an hourly seedshape, which is the hourly load profile template. The resulting hourly forecast will have an hourly profile similar to the seedshape, but the highest hourly load in each month will match the forecasted monthly peaks, and the sum of the hourly loads in each month will equal the forecasted monthly NEL. The seedshapes for each standalone company were selected by determining which historical month had weather that was most similar to normal weather. The hourly loads for that month were then adjusted to ensure the peak day occurs on a weekday, and this process was repeated for each of the companies. Additionally, the Gulf hourly seedshape was adjusted to reflect Eastern time zone.

VI. SUMMARY

Q. Please provide a summary of the forecasts for customers, energy sales, and peak demands for years 2022 and 2023.

A. Table JKP-14 summarizes the consolidated forecasts for customers, retail energy sales, and summer peak demands for years 2022 and 2023.

Table JKP-14		
Consolidated FPL Forecast Summary		
	2022	**2023**
Total Retail Customers (average)	5,717,534	5,785,456
Retail Delivered Sales (GWh)	122,083	122,980
Summer Peak Demand (MW)	27,205	27,661

These forecasts were developed using well-established methods that have consistently provided accurate and reliable forecasts that are used for all regulatory and planning purposes.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Jun K. Park was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF JUN K. PARK

DOCKET NO. 20210015-EI

JULY 14, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jun Park, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I submitted written direct testimony on March 12, 2021, together with Exhibits JKP-1 through JKP-5.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain portions of the direct testimony of Daniel Lawton submitted on behalf of the Office of Public Counsel ("OPC"). Specifically, I respond to certain questions and recommendations raised by OPC witness Lawton regarding the economic projections used in Florida Power & Light Company's ("FPL") forecasts and FPL's forecasted customer and energy sales growth rates for 2021-2025.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony demonstrates that, contrary to OPC witness Lawton's assertion, FPL's economic projections used in this proceeding appropriately considered and accounted for the known or reasonably expected fiscal and monetary policies and the rapid recovery from the COVID-19 pandemic that could improve economic growth. My rebuttal testimony also demonstrates that

FPL's forecasted growth rates are not understated as suggested by OPC witness Lawton and, in fact, are significantly stronger than the historical and forecasted growth rates relied upon by Mr. Lawton.

As explained in my direct testimony, the forecasts presented in this rate proceeding were developed using well-established and proven methods which incorporate inputs from leading industry experts and were the best available information at the time the forecast was developed. The forecasts for years 2022 through 2025 are reasonable and appropriate for rate setting purposes.

II. ECONOMIC PROJECTIONS

Q. OPC witness Lawton contends that the test years in this case should be limited to the 2022 test year because the forecasting uncertainty surrounding the 2020 pandemic makes estimates beyond 2022 unreliable. Do you agree with his recommendation?

A. No. OPC witness Lawton's claims regarding forecast uncertainty are based on incorrect and misleading statements regarding the assumptions I used to develop the economic projections and the validity of those forecasts.

Q. Before responding to OPC witness Lawton, do you have any general observations about his concerns regarding forecasting uncertainty?

A. Yes. First, it is standard industry practice to rely on forecasts of customers, energy sales, and peak demands for various planning and regulatory purposes, including rate proceedings such as this. It is also well known that no one can predict with absolute precision the actual number of customers, energy sales, and peak demand in the future. In other words, forecasting by definition always includes an element of uncertainty. This is precisely why FPL relies on well-established and statistically sound forecasting methods and input assumptions from industry experts. Additionally, the introduction of events, such as the pandemic, does not invalidate the need for reliable forecasts for utility planning and rate making.

Second, although OPC witness Lawton questions FPL's economic forecast for years 2023 through 2025, he does not question the economic forecast for the 2022 test year. The fundamental flaw with Mr. Lawton's logic is that the economic forecast for the 2022 test year relies on the same macroeconomic assumptions that were used to develop the 2023 through 2025 forecast, and the impacts from COVID-19 are expected to be less for 2023 through 2025 than for 2022 due to the temporal proximity to the COVID-19 pandemic. Therefore, it is not reasonable to claim the forecasts for 2023 through 2025 are unreliable.

Q. Does FPL's forecast account for the impacts of the monetary and fiscal policy benefits of the recent federal stimulus bills?

A. Yes. The May 2020 and August 2020 economic forecasts from IHS Markit that were relied upon for FPL's forecasts include the impacts of fiscal stimulus policies, such as the Coronavirus Aid, Relief, and Economic Security Act or CARES Act, and the extension of emergency unemployment benefits, as well as accommodative Federal Reserve monetary policies through 2026. Therefore, contrary to OPC witness Lawton's assertion, the economic projections used in FPL's forecasts do include the impacts of major fiscal and monetary policies that would enhance economic growth.

Q. Is FPL's unemployment assumption for the 2022 test year still reliable?

A. Yes. OPC witness Lawton compares the unemployment rate of 6.61 percent for year 2022 shown in MFR F-8, page 1 with the unemployment rate forecasts from other sources. However, this is not an appropriate comparison because it compares economic projections with a forecast model variable rather than comparing to the economic projection as provided by IHS Markit, which FPL relied upon for its customer, energy sales, and peak demand forecasts as explained in my direct testimony. The unemployment rate shown in MFR F-8 is an annual average of the variable used in FPL's small/medium commercial customer model. As provided in MFR F-7 attachment 16 of 29, this variable is lagged six months. The unlagged monthly unemployment rates, as provided by IHS Markit's August 2020 economic projections, were produced in response to OPC's Supplemental First Request for Production of Documents No. 36. The following table summarizes the lagged monthly unemployment rate forecasts as used in the calculation of MFR F-8 and the unlagged unemployment rate forecasts as provided by IHS Markit.

Table JKP-15

Florida Unemployment Rates		
	6 Month Lag	IHS Forecast
Jan-22	7.79	6.48
Feb-22	7.64	6.25
Mar-22	7.45	6.02
Apr-22	7.20	5.80
May-22	6.97	5.59
Jun-22	6.74	5.40
Jul-22	6.48	5.19
Aug-22	6.25	5.03
Sep-22	6.02	4.91
Oct-22	5.80	4.84
Nov-22	5.59	4.75
Dec-22	5.40	4.67
Jan-23	5.19	4.61
Feb-23	5.03	4.54
Mar-23	4.91	4.47
Apr-23	4.84	4.38
May-23	4.75	4.31
Jun-23	4.67	4.24
Jul-23	4.61	4.19
Aug-23	4.54	4.12
Sep-23	4.47	4.06
Oct-23	4.38	4.00
Nov-23	4.31	3.95
Dec-23	4.24	3.89

When comparing economic projections of the unemployment rate to other sources, it is appropriate to use the unlagged unemployment rates from IHS Markit's economic projections. As shown in the table above, the August 2020 economic forecasts from IHS Markit reflect that the unemployment rate is projected to be 4.67 percent by the end of 2022, which is consistent with the

2022 projection from the Congressional Budget Office cited by OPC witness Lawton.

III. FORECASTED GROWTH RATES

Q. Are FPL's customer and energy growth rates over the 2021 through 2025 period understated?

A. No. OPC witness Lawton's characterization of FPL's forecasted customer and energy sales growth is misleading and not based on comparable geographic areas. Mr. Lawton is comparing FPL's sales growth against that of the South Atlantic Census division, a geographic region which encompasses eight states[1] and the District of Columbia. However, FPL's energy sales make up less than 15 percent of the South Atlantic division.[2] It also is likely that the factors driving energy sales growth in FPL's service area differ significantly than those driving energy sales growth for the entirety of the South Atlantic division, as evidenced by the difference in forecasted growth rates.

OPC witness Lawton also overlooks that the U.S. Energy Information Administration's ("EIA") May 2021 Short-Term Energy Outlook includes forecasts for the Florida Regional Coordinating Council ("FRCC"), which is an

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[1] Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia

[2] 122.1 TWh / 835.4 TWh = 14.6%

122.2 TWh = Consolidated FPL retail delivered 2022 energy sales (Park direct testimony, Table JKP-6)

835.4 TWh = EIA's May 2021 outlook (2022 South Atlantic retail energy sales, table 7b) area that is comparable to FPL's service area in terms of both geography, demographics, and composition. In fact, FPL's Net Energy for Load ("NEL") represents almost 60% of FRCC NEL.[3] For the FRCC area, EIA forecasted NEL would decline by an average annual rate of -1.3 percent per year from 2020 to 2022. This corrected comparison based on comparable geographic areas clearly shows that FPL's projected growth rates are significantly stronger than EIA's projected growth rates.

Q. Do you have any other concerns regarding OPC witness Lawton's analysis of FPL's energy sales forecast?

A. Yes. On page 21, lines 5-10 of his direct testimony, OPC witness Lawton compares FPL's energy sales growth rates against a so-called "pre-pandemic" historical growth rate. However, this historical growth rate is based on a curiously chosen starting year of 2017, which includes lower energy sales due to Hurricane Irma. When Mr. Lawton's analysis is updated to reflect either 2015 or 2016 as the starting year, the result is a pre-pandemic historical growth rate of 0.2 percent, compared to FPL's forecasted energy sales growth rate of 0.8 percent. The updated analysis is shown below.

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[3] 135.6 TWh / 226.9 TWh = 59.8%
135.6 TWh = Park direct testimony, table JKP-6 (Consolidated FPL NEL)
226.9 TWh = EIA's May 6, 2021 Short-Term Energy Outlook, table 7d part 1 (FRCC NEL)

Table JKP-16

FPL Historical and Forecasted Sales Data - Corrected				
		Compound Growth		
Year	Delivered Sales GWh's	Beginning 2017	Beginning 2016	Beginning 2015
2015	118,760			
2016	119,056			
2017	116,821			
2018	120,355			
2019	119,536			
2020	120,134	0.94%	0.23%	0.23%
2022 FORECAST	122,083	0.81%		
2023 FORECAST	122,980	0.78%		

These results show that FPL's forecasted growth rates are in fact much stronger than both historical growth rates and EIA's forecasted growth rate.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Steven R. Sim was inserted.)

ERRATA SHEET

WITNESS: **STEVEN R. SIM – DIRECT TESTIMONY AND EXHIBIT SRS-11**

PAGE #	LINE #	CHANGE
75	13	Remove "$67,087" and insert "$68,116"
75	14	Remove "$66,684" and insert "$67,718"
Exhibit SRS-11 Page 1 of 1		For the year 2029, remove "2 x 100" and insert "1 x 100"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. 20210015-EI

MARCH 12, 2021

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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;

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[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.

Topic #2: The Manatee Modernization Project:

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.

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

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]

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

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 not 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

[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)

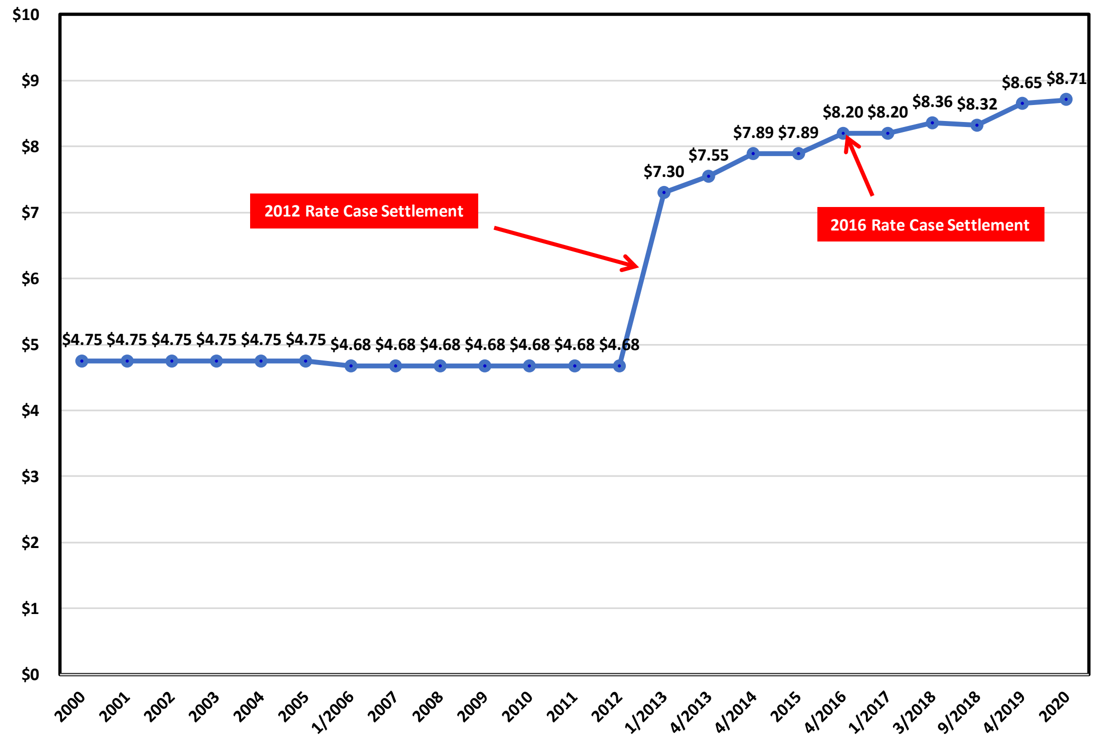
Year of Analysis	Benefit-to-Cost Ratio	CDR Incentive ($/kW-month)
2010 (DSM Plan)	3.10	$4.68
2015 (DSM Plan)	1.62	$7.89
2020 (DSM Plan)	0.97	$8.71

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.

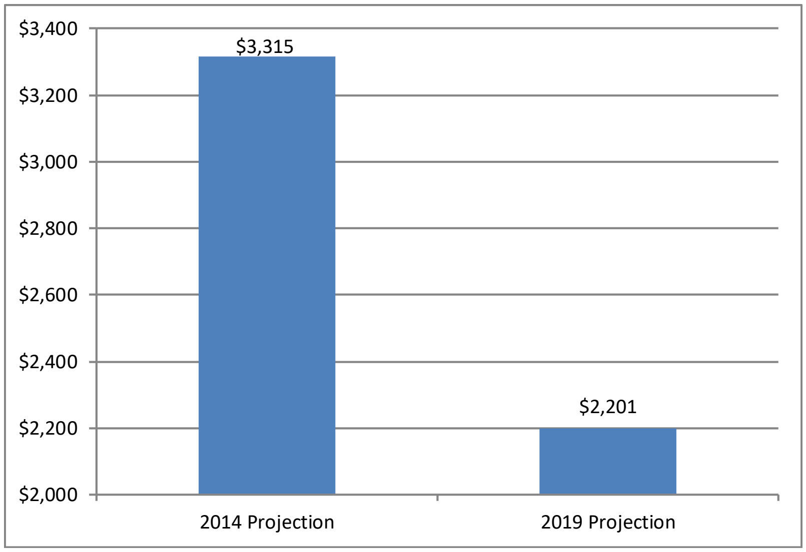
In addition, during the years in which the monthly incentive $/kW payment levels were increasing, a number of other utility costs that potentially could be avoided by DSM programs (*i.e.*, the benefits of DSM) have been trending steadily downward. Although this trend is a very good one overall for FPL's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

- <u>for both the FPL stand-alone system in analysis Step 2 and the single integrated system in analysis Step 3</u>: 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

[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.

(Whereupon, prefiled rebuttal testimony of Steven R. Sim was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. 20210015-EI

JULY 14, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is Florida Power & Light Company ("FPL"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following exhibit that is attached to my rebuttal testimony:

- Exhibit SRS-14: Inaccurate, Misleading, and/or Contradictory Statements Made by Intervenor Witnesses.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses a number of issues and problems found in the testimonies of five (5) witnesses who have presented testimony on behalf of intervening parties in this docket. These intervening parties and witnesses are listed below (in no particular order): Florida Industrial Power Users Group witness Pollock; Florida Retail Federation witness Georgis; Florida Rising/League of United Latin American Citizens of Florida ("LULAC")/Environmental Confederation of Southwest Florida witness Rábago; and CLEO Institute ("CLEO")/Vote Solar witnesses Whited and Wilson.

Q. How is your rebuttal testimony structured?

A. My rebuttal testimony is structured to address the five (5) topics identified above in the table of contents. I then close my testimony with a few concluding remarks.

Q. Please provide a summary of your testimony.

A. I will summarize the key points of my testimony in bullet format, first with an overall view of the intervenor witnesses' testimonies, then with regard to specific topics.

<u>An Overall View:</u>

- None of the intervenor witnesses I address in my rebuttal testimony has ever been employed by a utility as a resource planner. Therefore, none of the intervenor witnesses has had the opportunity, and the challenge, of actually planning an electric system not only through their own work, but through continual collaboration with utility system operators and transmission planners to ensure that the resulting resource plan is one that allows the utility system to be operated reliably under a myriad of situations.
- The intervenors produced no modeling of the FPL, Gulf Power Company ("Gulf"), and/or integrated FPL/Gulf systems upon which they could have based their testimonies. Therefore, the only system modeling analyses presented in this docket are those that FPL has provided and supported in its testimonies.

- As a result, the intervenor testimonies amount to little more than criticism of the results of FPL's analyses because those results are not the outcomes that the intervening parties desire, often for their own self-interest.

<u>Specific Topics:</u>

- <u>CDR and CILC Incentives:</u>
  - Not surprisingly, the witnesses for FIPUG and FRF are opposing FPL's proposed lowering of CDR and CILC incentives payments needed to return the two demand side management ("DSM") programs to cost-effectiveness status.
  - The misguided arguments these witnesses make in an attempt to block the needed lowering of incentives include: (i) pretending these two DSM programs are not DSM programs at all, but are just electric rates; (ii) basing the incentives only on fixed cost of generation, not on total costs of generation; (iii) basing the incentives on the cost of generation that FPL has already built; and (iv) basing the incentives on the cost of generation projected for another region of the country.

- <u>Inappropriately attempting to turn this docket into a DSM goals proceeding:</u>
  - The monthly incentive payment levels for CDR and CILC participants is an appropriate issue for this docket as directed by the

Florida Public Service Commission ("FPSC") in FPL's most recent (2020) DSM Plan proceeding (Docket No. 20200056-EG).

- However, discussion of other DSM-related issues is not appropriate in this docket. FPL's analyses that support its filing in this docket followed the FPSC's 2019 DSM Goals order which was based, at least in part, on the fact that the cost-effectiveness of DSM is declining to the point where many of FPL's and Gulf's DSM programs are no longer cost-effective.
- Nevertheless, several of the intervening witnesses appear to be using this docket to continue their opposition to the FPSC's decisions in the 2019 DSM Goals docket, and by trying to ignore the steady decline of DSM cost-effectiveness (a fact they do not dispute in their testimonies).
- They do so by again bringing up DSM-related issues raised in the 2019 DSM Goals docket (and in prior DSM Goals dockets), even though the FPSC has rejected these items repeatedly in DSM Goals dockets.

- <u>Unhappiness with the Results of FPL's Resource Planning Analyses:</u>
  - The intervening parties are unhappy that the resource plan FPL has developed – after extensive modeling and consultation with system

operations and transmission planning personnel – does not consist solely of the resource options they favor.

- For example, they are unhappy that a few gas-fueled resources were selected. They appear particularly unhappy that natural gas-fueled combustion turbines ("CTs") were selected in the resource plan for the Gulf area (despite the fact that the CTs were selected based on system economics and strongly supported by system operations and reliability considerations). They choose to ignore that the Gulf system (approximately 3,000 MW) has only an extremely small (44 MW) fast start generation capability, and even these few resources are scheduled to be retired soon. Consequently, once Gulf is no longer part of the Southern Company system, the Gulf area definitely needs new fast start generation that is capable of operating more than a few hours at a time.
- In short, the intervenors appear not to understand – or choose not to accept – the fact that sound resource planning is not solely an economic analysis, but rather must account for the ability to operate the resulting utility system in a reliable manner.

• <u>Numerous Inaccurate, Misleading, and/or Contradictory Statements:</u>
  - All of the witnesses whose testimonies I address here made statements that are clearly inaccurate, misleading, and/or contradictory. A listing of many of these misguided statements

appears in Exhibit SRS-14. Some of these statements are egregiously bad.

- One example is a claim that FPL's resource planning process is *"biased"* toward gas-fueled generation as CLEO/Vote Solar witness Wilson alleges (Wilson, Page 8, Lines 6-7). This is clearly not the case. As shown later in my testimony, a simple compilation of the resource additions, upgrades, and retirements presented in my direct testimony, and in the 2021 FPL/Gulf Ten Year Site Plan, shows that the net resource changes through 2030 include (approximately) 10,000 MW of new solar, 1,100 additional MW of new batteries, and a 100 MW reduction in total gas-fueled resources.
- The number, nature, and breadth of these misguided statements does not allow one to have confidence in the testimony of these intervenor witnesses.

Based on my review of their testimonies, the intervenor witnesses:

- Did not perform any modeling analyses of the FPL, Gulf, and/or integrated FPL/Gulf systems to support their contentions and recommendations;
- Did attempt inappropriately to turn this docket into a DSM goals proceeding; and,
- Did make many inaccurate, misleading, and/or contradictory statements in their testimonies.

As a result, these witnesses and their testimony should have no credibility for the purposes of this docket, and their recommendations should be rejected.

II. REBUTTAL OF INTERVENOR ARGUMENTS

1) A brief overview of intervenor testimonies and the lack of resource planning experience of the intervenor witnesses:

Q. Do these intervenors attempt to criticize FPL's resource planning analyses?

A. Yes.

Q. Have you examined the summaries of the work experience that each of these witnesses provided in their testimonies?

A. Yes.

Q. Do these summaries of work experience show that any of them have actually been employed by an electric utility as a resource planner?

A. No.

Q. Is their lack of this experience important when considering their testimonies?

A. Yes. Planning a utility system must, among other requirements: maintain reliable service, minimize electric rates, account for the current and projected transmission system strengths and constraints, and ensure that the resulting utility system can be successfully operated by the system operators under a myriad of potential situations and circumstances. Thus, it is a collaborative task that requires ongoing interaction with many other business units of the utility. For those reasons, it is a task that one cannot truly understand how to perform solely from reading or writing papers, or even running models outside of working in a utility. The intervenor witnesses do not have the requisite experience to fully understand how a utility system is actually planned.

Q. Do these intervenor witness testimonies provide any modeling analyses of the FPL, Gulf, or FPL/Gulf integrated systems?

A. No.

Q. In short, the intervenors attempt to criticize FPL's resource planning analyses, but have not performed any modeling analyses of their own, nor do they have the requisite experience to fully understand how a utility system is actually planned. How should their testimonies be evaluated?

A. I believe that anyone evaluating the testimony presented in this docket should put appropriate weight on: the depth and collaborative experience of the individuals supplying testimony, whether the individuals performed any modeling analyses of the FPL, Gulf, and/or FPL/Gulf systems, and the objectives of the testimony. Accordingly, one should appropriately discount the testimony of individuals who do not have the requisite experience, have not performed modeling analyses for the FPL, Gulf, and/or FPL/Gulf integrated systems, and whose testimony amounts to unfounded criticisms based on their favored resources.

Q. Do you believe that these witnesses' lack of requisite work experience has led them to make inaccurate, misleading, and/or contradictory statements in their testimonies?

A. Yes. Exhibit SRS-14 presents a compilation of some of those problematic statements, and the remaining sections of my rebuttal testimony will examine a few of those statements.

2) <u>The intervenor witnesses' efforts to oppose the proposed lowering of CDR and CILC program incentive payments that are needed to return these DSM programs to cost-effective status:</u>

Q. Which of the intervenor witness testimonies will you be addressing in this section of your rebuttal testimony?

A. In regard to comments made about the CDR and CILC programs, and FPL's proposed lowering of the monthly incentive payments, I will examine the testimonies of witnesses Pollock, Georgis, and Rábago.

I will start with a statement from witness Pollock in which he attempts to explain an earlier statement of his that (paraphrasing) 'FPL's cost-effectiveness analysis of the CDR and CILC programs is not valid'. Witness Pollock argues that CDR and CILC should be viewed as simply electric rates, not as DSM programs. (Page 60, lines 9-11)

Q. Are the CDR and CILC programs DSM programs?

A. Yes. They were designed as DSM programs, approved by the FPSC as DSM programs, and have been evaluated as DSM programs in DSM Goals and DSM Plan dockets since their inception.[1] Furthermore, utility costs, such as administrative costs and incentive payments, for these programs have been recovered under the Energy Conservation Cost Recovery ("ECCR") clause as they are for other DSM programs.

Each of these two DSM programs does have a tariff sheet associated with the program. However, the tariff sheets primarily serve to explain program eligibility, terms, conditions, and how the monthly incentives will be distributed. As such, the tariffs are simply one facet of the DSM programs. FPL's residential and small business load management DSM programs are similarly structured.

Q. What is the importance of CDR and CILC being DSM programs?

A. Because CDR and CILC are DSM programs, they are DSM resource options that compete with other DSM options, and with supply options, for a role in FPL's resource plan. And, as explained in my direct testimony, DSM programs are periodically evaluated to ensure that they remain cost-effective.

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[1] The CILC program was closed to new participants in 2000 and, therefore, has not been addressed in DSM Goals or DSM Plan dockets since that date.

Q. What does intervenor witness Pollock say about how the cost-effectiveness of these DSM programs should be evaluated?

A. Witness Pollock attempts to make several points to support his view about how cost-effectiveness evaluations of these DSM programs are carried out. I will paraphrase his contentions as follows:

- The FPSC has always used avoided capital costs only in determining the cost-effectiveness of load management DSM programs. (Page 8, lines 33-35);
- The value of load management programs can be judged by whether they have actually avoided generation in the past, and by the costs of that past avoided generation. (Page 61, lines 6-9); and,
- FPL's AURORA model accounts for both fixed and variable cost impacts on a utility system, and variable costs impacts are not needed to evaluate the cost-effectiveness of the CDR and CILC programs. (Page 63, lines 4-10).

Q. Do you agree with witness Pollock's contentions and his view of how cost-effectiveness of DSM programs is evaluated?

A. No. Witness Pollock does not understand, or simply ignores, how cost-effectiveness analyses of DSM programs are actually performed in Florida.

Q. How do the FPSC and FPL evaluate the cost-effectiveness of DSM programs?

A. To provide a direct comparison with witness Pollock's statements, I'll summarize the actual DSM evaluation approach as having two key facets. First, the evaluation of DSM programs is typically performed by: (i) examining future changes in the utility's resource plan that could potentially result from the DSM option, and (ii) in the course of that examination, accounting for all readily quantifiable fixed and variable cost impacts on the utility system caused by the DSM option that will be reflected in the electric rates with which all customers will be served. Second, the DSM cost-effectiveness approach is not, as witness Pollock's statements would have one believe, a "look back" at whether a DSM program avoided/deferred another resource option in the past; nor is it an examination of fixed costs only.

Q. How long has this approach been used by the FPSC and FPL to analyze DSM?

A. The basic cost-effectiveness analysis approach has been utilized in Florida, and elsewhere, since at least the early 1980s. It is a fundamentally sound approach to determine whether DSM programs are beneficial to a utility's general body of customers. By the fact that the DSM analytical approach accounts for all cost impacts that will be reflected in electric rates, this approach is identical to how generation resource options are analyzed. FPL, and other Florida utilities, have filed hundreds, if not thousands, of DSM cost-effectiveness analyses over the years using the FPSC's approved cost-effectiveness methodology. That methodology provides a projection of cost impacts, including both fixed and variable costs, that would result from a DSM option avoiding or deferring the generation option that the utility would otherwise build. This information is available in the applicable FPSC dockets.

Q. Why is it important to realize that DSM cost-effectiveness analyses has always accounted for both fixed and variable cost impacts on the utility system?

A. It is important to realize this in light of comments witness Pollock made regarding the appropriateness of FPL using the AURORA optimization model to analyze the value from both existing and new participants in the CDR and CILC programs. Witness Pollock concludes that the AURORA model is the wrong tool with which to measure DSM cost-effectiveness because it includes both fixed and variable costs. This conclusion is clearly at odds with the fact that, for years, DSM cost-effectiveness analyses, using the FPSC's approved cost-effectiveness methodology, have accounted for both fixed and variable costs.

Q. Why was the AURORA model used in FPL's analysis of the CDR and CILC programs?

A. In my direct testimony, I described that the FPSC's approved cost-effectiveness methodology was first used by FPL in its attempt to evaluate the cost-effectiveness of the CDR program. The projected benefit-to-cost ratio for the CDR program using the FPSC's approved methodology was 0.45.[2]

[2] A benefit-to-cost ratio of at least 1.0 is needed for a DSM program to be cost-effective. Thus, a benefit-to-cost ratio of 0.45 indicates that signing up new participants for the CDR program is clearly not cost-effective. Based on this ratio of 0.45, if FPL had stopped its analysis at this point, the result would have been a proposed monthly incentive payment much lower than the $5.80/kW that FPL is proposing in this docket.

However, the FPSC's approved cost-effectiveness methodology examines the question of DSM cost-effectiveness solely from the perspective of signing up new participants. The CILC program is closed to new participants but continues to pay millions of dollars each year in on-going incentive payments to existing participants. The CDR program does sign up new participants each year but has many more existing participants for whom annual incentive payments are made. The CDR program's total annual incentive payments are also in the millions of dollars. In order to address the cost-effectiveness of continuing to make incentive payments to all of these existing program participants at the current levels, another cost-effectiveness approach was needed.

The AURORA model is a resource planning optimization tool that FPL is successfully using in its resource planning work. And, as already noted in witness Pollock's statements, the model accounts for both fixed cost and variable cost impacts. In that regard, it is similar in overall concept to the FPSC's approved cost-effectiveness methodology.

When DSM levels in question are small (for example, only a few MW), it can be difficult to accurately determine the impact of DSM in models such as AURORA because those impacts are small in relation to the costs of the entire utility system. However, in the case of the CDR and CILC programs, whose combined MW capability exceeds 800 MW (*i.e.*, the size of a fairly large generating unit), there is no problem in projecting the impacts of these programs with a model such as AURORA.

FPL's analysis of the Manatee modernization project is a useful analogy. That analysis was performed by a comparison of two resource plans – one plan with the Manatee units remaining in service and the other plan assuming the Manatee units are retired. With the 800+MW size of the combined CDR and CILC capability, a similar approach using the AURORA model was utilized – a comparison of two resource plans, one plan with the programs and other plan assuming the programs are ended.

Therefore, FPL analyzed the cost-effectiveness of CDR and CILC using two approaches. First, the FPSC's approved cost-effectiveness methodology was used. Second, an AURORA model-based analysis was performed. Both approaches account for fixed and variable costs, but the use of AURORA allowed FPL to properly account for the costs and benefits from existing program participants. In short, the use of the AURORA model was appropriate and produced reliable results that I have included in my testimony and recommendations.

Q. What about witness Pollock's statement about whether the Commission has used a production cost simulation model?

A. Witness Pollock's statement that the FPSC has not used a production cost simulation model to evaluate cost-effectiveness (Page 62, lines 9-11) may be correct by default because, to my knowledge, the FPSC and its Staff do not run production cost models. However, the FPSC's approved DSM cost-effectiveness methodology does in fact simulate the impacts on the electric system – accounting for both fixed and variable costs – that are obtained when a model like AURORA is used. In addition, FPL has previously used production cost models in at least the last two DSM Goals dockets (Docket No. 20130199-EI and Docket No. 20190015-EG, respectively) to examine resource plans with and without DSM portfolios. Finally, the FPSC frequently evaluates the results from such models in resource planning dockets such as need determinations. Thus, witness Pollock's contention is both misleading and misguided.

Q. Didn't a couple of the intervenor witnesses claim that, based on fixed cost avoidance, CDR credits should increase?

A. Yes. Both witness Pollock and witness Georgis claimed, based on their individual views of how DSM cost-effectiveness is evaluated, and using different fixed costs, that CDR credits should actually be increased. (Pollock, Page 66, lines 13-20 and Georgis, Page 19, lines 13-15).

Q. Do you agree with these statements?

A. No. There at least four things that are inherently wrong in the evaluation approaches described in these statements. First, both witnesses are examining fixed capacity costs only and ignoring other cost impacts, especially variable costs, which are accounted for in DSM cost-effectiveness analyses.

Second, witness Pollock incorrectly attempts to use historical generation costs to justify future incentive payment levels for the DSM programs. The correct approach is to use projected future costs when contemplating future incentive payments. Third, witness Georgis incorrectly bases his calculations on cost projections from the SERC-SE region when he should be using FPL-specific cost projections.

Fourth, witness Pollock's historical cost projections include types of generation that are not the appropriate avoided unit for purposes of DSM analyses on FPL's system and, therefore, are not used in FPL's DSM analyses.

Q. What is the appropriate type of generating unit for purposes of FPL's DSM analyses.

A. For most of the last 20 years, the most cost-effective generation resource option for FPL's system has been combined cycle ("CC") capacity. Therefore, for purposes of FPL's DSM cost-effectiveness analyses, the appropriate avoided unit has been FPL's next projected new, build-from-scratch (new) CC unit.

Q. Why are CT units or CC/steam unit modernization projects not appropriate for FPL as avoided units in DSM cost-effectiveness analyses?

A. The CT units that FPL has added in the last few decades have either been needed replacements for soon-to-be retired CT/GT capacity, or to address a need for new fast start/longer duration capability in a specific region (*i.e.*, the Ft. Myers CTs). Therefore, from a practical perspective, this capability cannot be avoided by DSM.

In regard to modernization projects, these CC units have inherent advantages in regard to land, water, transmission, and/or fuel supply infrastructure, compared to new CC units. As a result, the CC units in modernization projects are more economic than new CC units. FPL decided, in large part, not to use CC units in modernization projects as avoided units in DSM cost-effectiveness analyses because even less DSM would have been found to be cost-effective.[3]

Q. Please discuss the new CC units FPL has recently used in its DSM analyses.

A. In FPL's 2009 and 2014 DSM Goals filings, a projected new 2019 CC unit was used as the avoided unit. In its 2019 DSM Goals filing, a projected new 2026 CC unit was used as the avoided unit.

Figure SRS-3 below provides a comparison of the projected $/kW installed cost of these CC units that were used in these DSM dockets.[4] This figure shows that the $/kW installed costs for new CC units have significantly declined from 2009 to 2019.

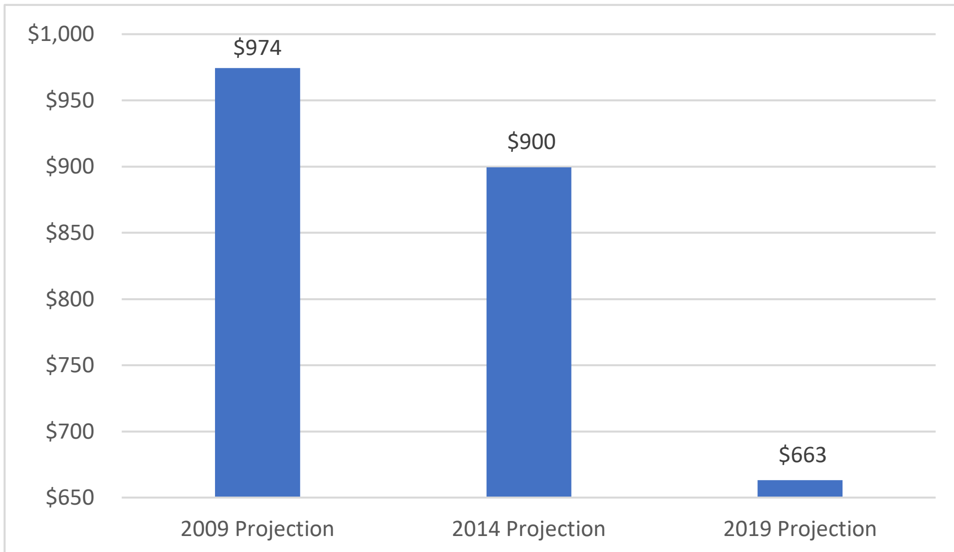
[3] The soon-to-be-completed Dania Beach modernization project marks the last modernization opportunity in FPL's area for the foreseeable future.

[4] The figure formerly was previously provided in my direct testimony in the 2019 DSM Goals docket (Docket No. 20190015-EG) and the values represented in-service year dollars.

Figure SRS-3

Comparison of CC Installed Costs in DSM Analyses: 2009 to 2019

($/kW, in-service year)



Q. **Returning to witness Pollock's testimony, his Exhibit JP-13 shows the actual $/kW cost number of generating units/projects built by FPL during the period 2013 through 2020, plus projected costs for two additional units/projects that will come in-service in 2021 and 2022. Is the information regarding actual costs shown in his exhibit consistent with the declining cost trend shown above in Figure SRS-3?**

A. Yes, if his exhibit had covered two earlier years. In his exhibit, the only unit that meets FPL's criterion of being a new CC unit – and not a modernization of an existing steam or CC unit, a CT/GT replacement project, or a solar project – is the 2019 Okeechobee CC unit. That unit is shown with a $677/kW installed cost. Prior to the Okeechobee CC, FPL's last new CC unit was the West County Clean Energy Unit 3 ("WCEC 3") which came into service in 2011. The installed cost for the WCEC 3 unit was $709/kW in that year's dollars. This unit does not appear in his exhibit because the exhibit did not address any year prior to 2013.

To provide a more meaningful comparison of the installed costs of these two units, one would need to compare them in the same year dollars. Applying a 2.5% annual escalation rate to the WCEC 3 cost to bring its cost up to 2019 dollars, results in an adjusted installed cost for WCEC 3 of $864/kW. Thus, the installed cost for the 2011 CC was approximately 28% (864/677 = 1.28) higher than the cost of the 2019 Okeechobee CC in terms of same year dollars. Therefore, this comparison of actual costs demonstrates that installed costs for new CC capacity have been declining by a significant amount during the years 2011 through 2019.

Q. Did witness Pollock have any other comments regarding a trend in generation costs?

A. Yes. He addresses historical costs of CT capacity in the Midcontinent Independent System Operator ("MISO") area discussion of CT prices in the MISO area as follows:

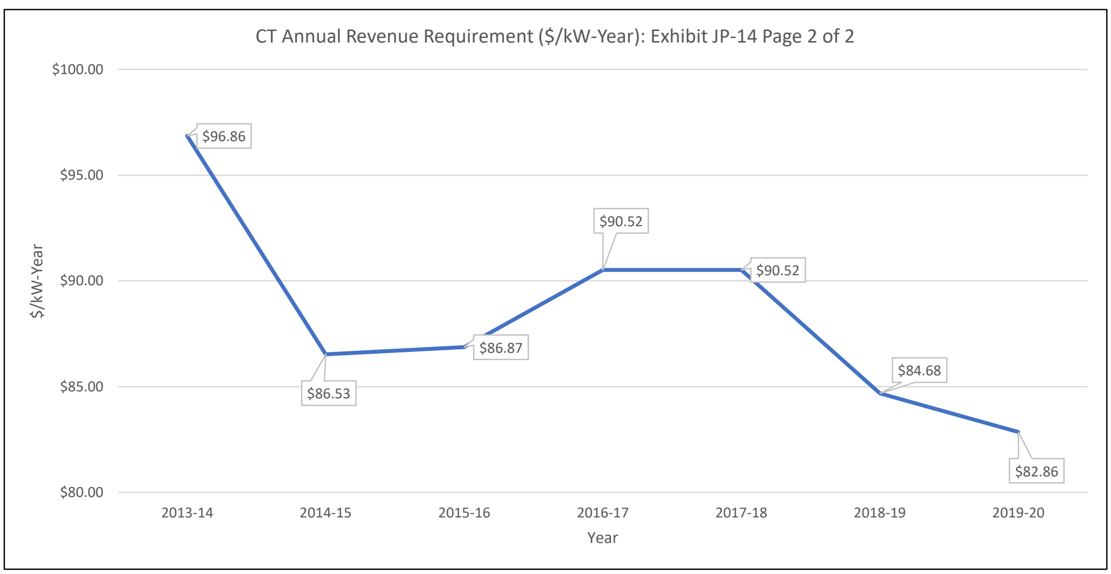
"…I have provided a history of CONE prices published by MISO in its annual PRA. The CONE prices shown reflect the cost to construct a new CT in MISO local resource Zone 9, which includes Louisiana, Mississippi and Texas (along the Gulf Coast). As can be seen, the CONE prices have varied over time.

However, there is no discernable decline…". (Page 64, lines 17-19, and page 65, lines 1-2). (emphasis added)

For the purpose of examining his statement, I will ignore the fact that he appears to be comparing prices for stand-alone CT units, not for new CC units. Although witness Pollock does not indicate in this statement where these values *"can be seen"* in his testimony, values for *"Capital Cost of New Combustion Turbines"* from *"MISO PRA Filings (Louisiana, Mississippi, Texas)"* are shown in his Exhibit JP-14, page 2 of 2. In that exhibit, he uses these cost values for the years 2013-2014 through 2019-2020 in a calculation. Those values are shown below in Figure SRS-4:

Figure SRS-4

Capital Cost of New CTs: MISO 2013-14 Through 2019-2020



Although witness Pollock describes these actual costs as showing *"no discernable decline"*, it certainly seems to me that there is a distinct decline in costs from the starting point value over this time period. This indicates that FPL does not appear to have been alone in seeing a decline in generation capital costs over the last decade.

Q. Did witness Georgis attempt to describe his calculation approach as an "FPL methodology"?

A. Yes. He attempted to do so with the following two statements:

"Q. Using <u>Mr. Sim's methodology</u>, could these projections be applied to calculate the CILC/CDR credit values in <u>FPL's calculation methodology</u>?" (Page 18, lines 16-18) (emphasis added); and,

"Applying <u>FPL's methodology</u> of projected changes in costs and value for capacity…" (Page 19, line 13) (emphasis added).

Q. Is this "FPL's" or "your" methodology?

A. Neither. As much as witness Georgis may wish it were so, FPL's methodology is definitely <u>not</u> to: (i) find some capacity-only cost projection that is not FPL-specific, (ii) determine the year-to-year escalation factors from that projection, and (iii) apply those escalation factors to the current, non-cost-effective CDR incentive to increase the payment level (which would only make the non-cost-effective CDR and CILC programs even less economic).

As previously described, FPL's approach in analyzing the appropriate incentive levels for the CDR and CILC programs was to account for all fixed and variable cost impacts from the programs in two separate and independent analyses. One analysis used the FPSC's approved DSM cost-effectiveness methodology, and the other used the AURORA model. Both analysis approaches found that the programs are no longer cost-effective with their current incentive levels.

Q. Witness Pollock appears to believe that cost-effectiveness tests are used in DSM Goals dockets only to determine whether a new DSM program should be implemented or whether an existing program should be expanded or closed (Page 62, lines 5-8). Is this correct?

A. No. Witness Pollock appears to believe there are only two possible actions resulting from the results of a DSM cost-effectiveness analysis for an existing DSM program: to sign up more participants or close the program to new participants. He is not correct.

There are two more possible actions that can be taken: to completely cancel a non-cost-effective DSM program, and to change the costs, usually the program's incentive payments, for a non-cost-effective DSM program to return the program to cost-effective status. All four of these actions have been taken by Florida utilities and the FPSC over the last 30-plus years. The last of these four possible actions, adjusting the incentive payment to return the program to cost-effective status, is the action needed for the CDR and CILC programs and is the action that FPL is proposing.

FPL has adjusted incentives for its DSM programs over time. It has lowered the incentives, when appropriate, to address declining DSM cost-effectiveness and to save money for all customers. A good example of that is FPL's residential load management ("On-Call") program. The On-Call program is approximately the same size as the CDR and CILC programs combined in terms of MW reduction capability. The incentive for the On-Call program has been adjusted downwards twice in the last 10 years. FPL has also reduced incentives for other DSM programs (FPL's residential HVAC efficiency program, for example) for the same reasons.[5]

Therefore, FPL's proposed lowering of incentive payments for the CDR and CILC programs to return them to cost-effective status and save money for customers is not at all unusual and it is an action that is taken when needed.

Q. Witness Pollock states that FPL should conduct a customer survey before changing incentive levels for the CDR and CILC participants (Page 65, lines 14-18). Do you agree?

A. No. FPL does not believe that a survey of either program participants, or a survey of the remaining (roughly) 5 million FPL customers who are <u>not</u> participants in the CDR and CILC programs, and who are paying monthly for non-cost-effective incentives for these programs through ECCR clause charges, is needed. The issue is simply that the programs are no longer cost-effective

[5] FPL has also <u>increased</u> incentives for DSM programs when appropriate. For example, this action was taken in 2006 after very high electrical loads during the Summer of 2005 resulted in FPL addressing a projected lower level of reserves.

and the monthly incentive levels need to be lowered to return the programs to cost-effective status. However, FPL believes there is evidence that many, if not most, of the current program participants will remain on the program if incentive levels are lowered.

As explained in my direct testimony, 100% of the current CILC participants, and approximately 75% of the CDR participants, all signed up for the programs at incentive levels that were 20% lower than the proposed new incentive level. In addition, Gulf is now signing up participants for a somewhat similar load management program at an incentive lower than the proposed \$5.80/kW-month level. For at least these two reasons, FPL believes that many, if not most, CDR and CILC participants will continue with the programs. If that does not turn out to be the case, then FPL will attempt to sign up new CDR program participants, perhaps in the Gulf area, and/or will add other resources that will be economic compared to these currently non-cost-effective DSM programs.

Q. Do you agree with witness Pollock's statement that a participant's assessment of risks and benefits if the incentive payment is lowered will lead to a participant changing from CDR or CILC service to firm service? (Page 66, lines 2-7)

A. No. His argument is not convincing. Witness Pollock also states that participants *"have to incur cost to be able to safely curtail load"*. I agree with that statement. However, 100% of the CILC participants signed up for that program prior to the year 2001 or 20 years ago. In addition, approximately 75%

of CDR participants signed up for that program prior to 2012 or almost 10 years ago. If these participants needed to incur costs to safely curtail load, it seems logical to assume they would have already done so prior to/at the time they joined the programs (which would be a minimum of 10 years ago). If these costs consisted largely of capital equipment, such as a backup generator, those capital costs became sunk costs years ago. Those sunk cost should not be a major factor when a participant considers whether to remain with the program.[6]

Q. Do you agree with witness Pollock's claim that the AURORA model results cannot be verified without a detailed audit (Page 63, lines 12-13)?

A. No. The AURORA model is a commercially available optimization model that is widely used in the U.S. by utilities in their resource planning. Thus, it has been examined by each utility that has made the decision to use it, and the use of the model has then been evaluated by the state utility commissions for those utilities. Each of these utilities has found it to be an accurate and valuable planning tool. And, as explained in my direct testimony, FPL conducted its own side-by-side comparison testing of AURORA and its then-current optimization model, EPRI's EGEAS model, in the second half of 2018 and early 2019. The results from the two models were comparable, and AURORA has the capability to simultaneously plan for transmission constrained areas such as Gulf and FPL, a capability that was needed with NextEra Energy's acquisition of Gulf.

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[6] Note that backup generators also allow these commercial/industrial customers to have continued operation during/after storm outages, thus making it even more unlikely that customers considering dropping out of the programs would do so because they wish to stop annual maintenance costs for the backup generators.

As a result, FPL switched away from the EGEAS model and has used the AURORA model since early 2019. Analyses using this model have supported the FPL/Gulf 2020 and 2021 Ten Year Site Plans. FPL has confidence in the model and plans to continue using AURORA in its resource planning work for the foreseeable future.

3) The intervenors' inappropriate attempt to turn this docket into a DSM goals proceeding:

Q. You indicated earlier that the intervenor witnesses have attempted to turn this docket into a DSM goals proceeding?

A. Yes. Witnesses Rábago, Whited, and Wilson attempted to do so in their testimonies.

Q. Based on FPL's filing and the issues in this docket, do you believe that attempt is appropriate?

A. No. There are at least three reasons for this. First, there is only one specific DSM issue in this docket, as directed by the FPSC in FPL's 2020 DSM Plan docket (Docket No. 20200056-EG). That issue is FPL's proposal to lower the monthly incentive payments for the CDR and CILC programs. Second, FPL's treatment of DSM in its analyses followed the FPSC's latest direction regarding DSM as expressed in their 2019 DSM Goals order. Third, two of the factors that were undoubtedly considered by the FPSC in this most recent DSM Goals order – the continued decline in DSM cost-effectiveness, and that most of FPL's and Gulf's DSM programs are no longer cost-effective – were accounted for at the start of FPL's analyses and these facts have not changed.

Nevertheless, these intervenor witnesses' testimonies attempt to continue to re-litigate the FPSC's 2019 DSM Goals docket decisions in this docket. They did so by trying to introduce into this docket a number of issues debated in the 2019 DSM Goals docket, and which are again being raised in the proposed amendment to Rule 25-17.0021, F.A.C., Goals for Electric Utilities ("DSM Rule") in Docket No. 20200181-EI. These issues have no direct bearing on this docket and are inappropriate for this docket.

Q. Would you please provide a brief summary of some of the DSM-related issues that the intervenor witnesses are trying to introduce into this docket?

A. Yes. Because I believe those issues to be inappropriate topics for this docket, I will not discuss each issue in detail. However, the actual statements made by the intervenor witnesses in regard to these DSM-related issues, plus FPL's correction of their misguided statements, are presented in Exhibit SRS-14.

The following is a brief listing of the DSM issues these witnesses have attempted to inject into this docket[7]:

[7] Note that the objective of raising each of these issues is to make DSM options appear more economic than they actually are, or to otherwise end up with more DSM regardless of cost-effectiveness.

- Do not use the RIM test (despite the fact that it is the only DSM cost-effectiveness test that allows a true apples-to-apples comparison with generation options);
- Do not use the two-year payback screen to address free ridership for DSM (despite the fact that this screen provides a logical and simple approach to addressing free riders as required in Florida);
- Do set DSM goals based on an arbitrary MWh reduced vs MWh sold basis (despite the fact that the FPSC rejected this approach in both the 2014 and 2019 DSM Goals dockets); and,
- Do use a $/MWh (or cents/kwh) approach of comparing DSM versus supply options to make resource decisions (despite the fact that this approach is fundamentally flawed and the FPSC has rejected this approach several times).[8]

Q. How did FPL account for DSM in the Steps 1 through 3 analyses that support its filing in this docket?

A. All of these analyses assumed, as a given, the most recently set (2019) DSM Goals amounts for both the Gulf and FPL areas which addressed the years 2020 through 2024. In addition, FPL assumed additional DSM, again as a given, for the years 2025 through 2030 based on the amount of DSM that FPL projected was cost-effective after 2024 in its 2019 DSM Goals filing to the FPSC.

[8] The fundamental flaws in this approach have also been detailed in rebuttal testimony of mine in FPSC dockets more than once: 2009 DSM Goals Docket No. 20080407-EG; 2009 Nuclear Cost Recovery Clause ("NCRC") Docket No. 20090009-EI; 2010 NCRC Docket No. 20100009-EI; and 2014 DSM Goals Docket No. 20130199-EI.

Q. Please explain during what time periods FPL's Steps 1 through 3 analyses were performed.

A. The time period during which the initial Step 1 and 2 analyses were conducted was the second half of 2018 through the first Quarter of 2019. The current Steps 1, 2, and 3 analyses were conducted during the second half of 2020 through most of the first Quarter of 2021.

Q. Why are these time periods important to keep in mind in regard to consideration of DSM in these analyses?

A. By the second half of 2018, both FPL and Gulf were performing DSM cost-effectiveness analyses for the 2019 DSM Goals docket. At that time, it was apparent to both companies that the trend of declining cost-effectiveness for utility DSM programs that had begun about 10 years before was continuing.

Q. Can you demonstrate this trend of declining cost-effectiveness for utility DSM programs?

A. Yes. This is shown graphically in Figures SRS-5a and SRS-5b below. These figures show the results of cost-effectiveness analyses conducted for FPL's DSM programs from the 2010, 2015, and 2020 DSM Plan filings using the RIM test[9].

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[9] These graphic depictions of declining cost-effectiveness for FPL's DSM programs were previously provided in discovery in this docket in response to CLEO/Vote Solar's Second Request for Production of Documents, number 60. That response also provided graphs of DSM cost-effectiveness results using the TRC test which also show a trend of declining DSM cost-effectiveness. Thus, a trend of declining DSM cost-effectiveness is apparent regardless of which test, RIM or TRC, is used.

Figure SRS-5a

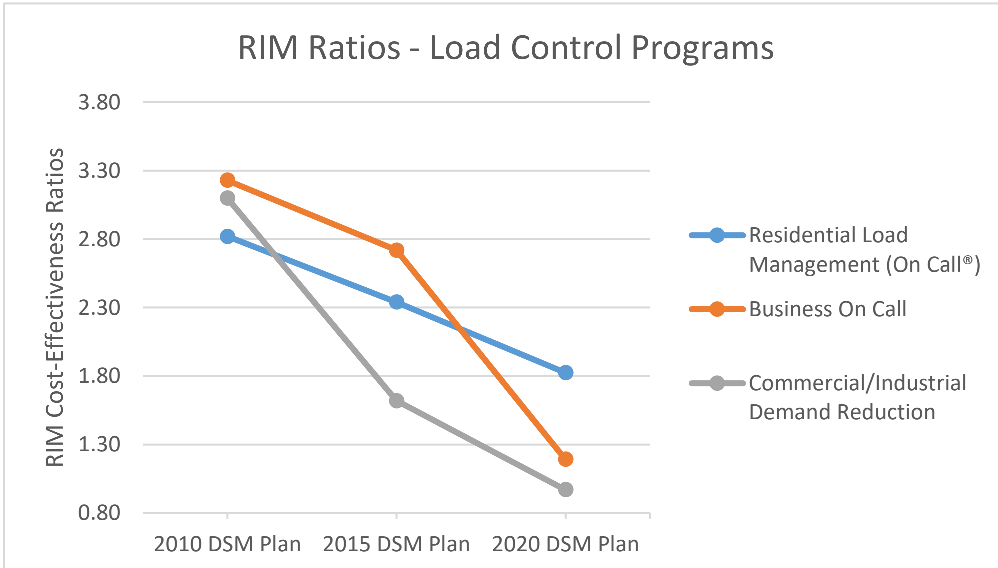
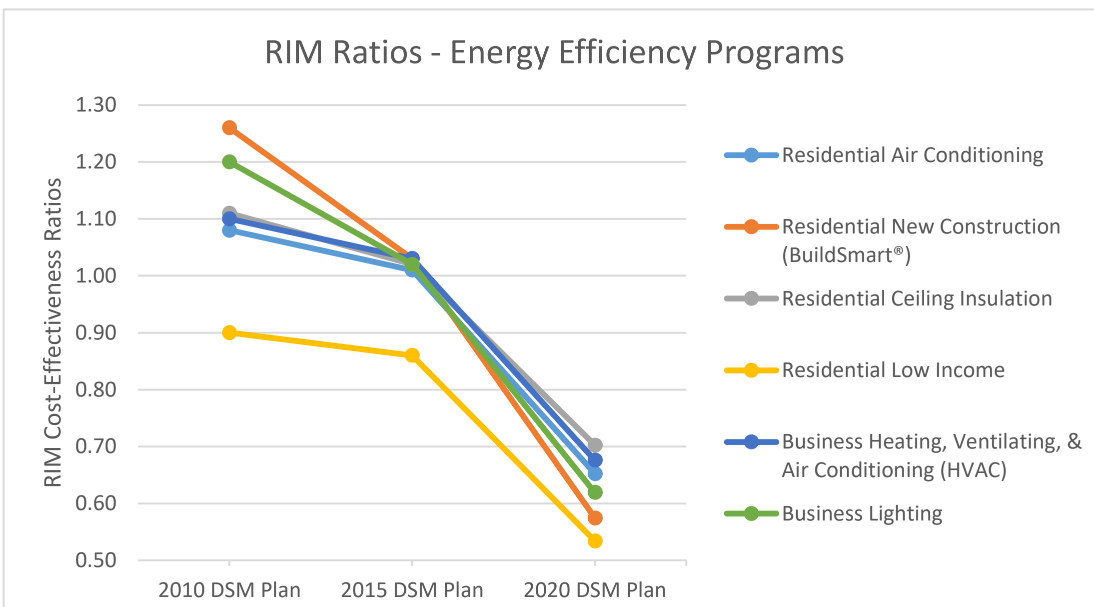


Figure SRS-5b



The trend of declining cost-effectiveness of DSM programs is clearly shown in these figures. Furthermore, in the 2019 DSM Goals docket, only a few of FPL's current DSM programs were still cost-effective, and none of Gulf's current DSM programs were cost-effective.

The 2019 DSM Goals docket had been completed in late 2019 which was before FPL's current Steps 1, 2, and 3 analyses began. In the 2019 DSM Goals docket, the FPSC essentially ordered the utilities to continue their then-current level of DSM, but only through the year 2024. In my opinion, the FPSC made its decision based at least partly on the evidence presented in the docket that: (i) the trend of declining cost-effectiveness for utility DSM was continuing, and (ii) most of the current utility DSM programs in Florida, including for FPL and Gulf, were no longer cost-effective.

As a result, the FPSC chose to reject the positions taken by several parties to the 2019 DSM Goals docket, including SACE and LULAC, to significantly increase Florida utilities' DSM Goals. And, as mentioned above, various intervenors are making the same arguments again in this docket.

Q. Did the results of analyses performed for the 2019 DSM Goals docket, plus the FPSC's decisions in that docket, contribute to FPL's decision to not evaluate additional DSM in its Steps 1, 2, and 3 analyses?

A. Yes. It was clear from the 2019 DSM Goals analyses being conducted as FPL's initial Steps 1 and 2 work was underway that additional DSM would not be cost-effective and, therefore, not a viable resource option in the Steps 1, 2, and 3 analyses. This conclusion was reinforced during 2019 by the results from the initial Steps 1 and 2 analyses. These results showed there were significant cost-effective improvements that could be made in the generation and transmission systems that would result in the Gulf and FPL systems becoming even more efficient and economic.

Simple logic dictates that if most utility DSM programs were not cost-effective on the Gulf and FPL systems that were the bases of the 2019 DSM Goals docket analyses, then these DSM programs would be even less cost-effective on a more efficient, more economic utility system.

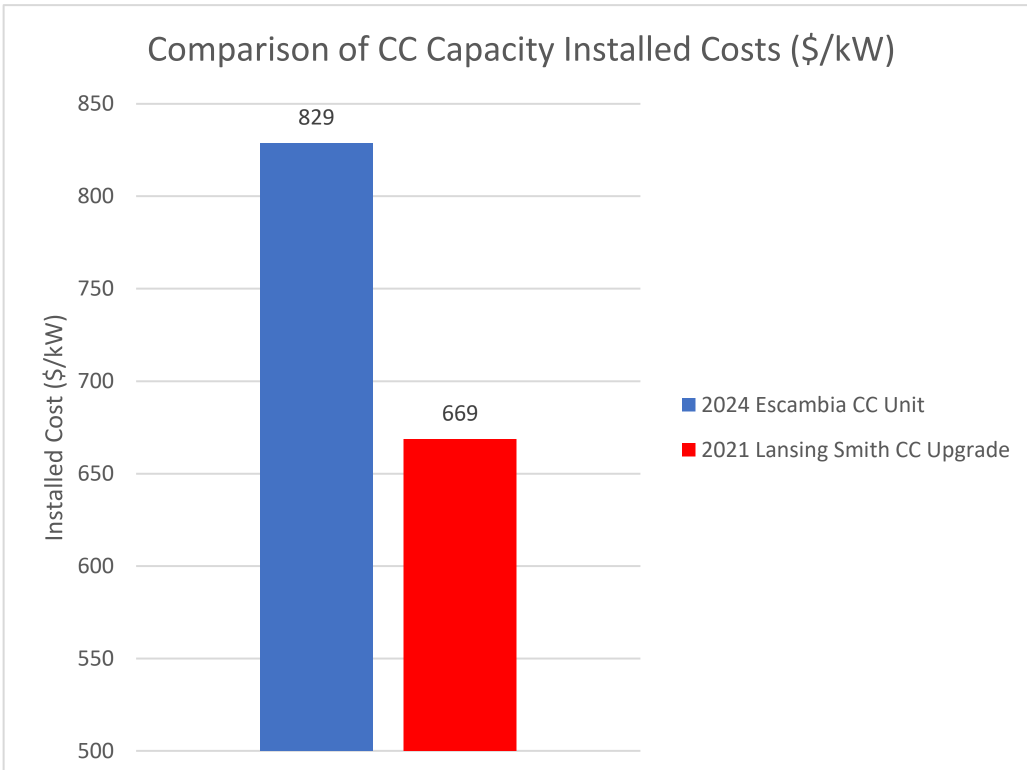
Q. Can you provide an example of the more efficient, more economical system?

A. Yes. I will provide two examples with the first example focusing on fixed costs. On pages 24 and 25 of my direct testimony, I discussed that a number of utility costs that could potentially be avoided or deferred by DSM were declining which, although good news for FPL's customers, was reducing the potential benefits of utility DSM programs. One of these costs is the cost of new generation. An examination of the cost of new CC capacity provides an example of how the Steps 1, 2, and 3 analyses have identified ways to make the FPL/Gulf integrated system more efficient and economic.

In Gulf's 2019 DSM Goals filing, the avoided unit against which its DSM was compared was a 2024 CC unit sited in Escambia County. One of the improvements selected in the initial Steps 1 and 2 analyses was an approximate

70 MW upgrade to Gulf's existing Lansing Smith CC unit. A comparison of the installed $/kW cost of these two CC capacity options, the new Escambia CC unit and the Lansing Smith upgrade, is provided in Figure SRS-6 below.

Figure SRS-6



The installed cost of the Escambia County CC that was used as the avoided unit in Gulf's 2019 DSM Goals analyses was $829/kW in 2024 dollars (as shown by the blue bar) and the installed cost of the already completed CC capacity upgrade was $621/kW in 2021 dollars. To more meaningfully compare the two cost values, the Lansing Smith upgrade cost value in 2021 has been escalated assuming a 2.5% annual escalator to provide a 2024 dollar value of $669/kW value (as shown by the red bar). Therefore, new CC capacity was added to the

Gulf area at an installed cost approximately 24% lower than the installed cost for the CC capacity that had been used as the avoided unit in Gulf's 2019 DSM Goals analyses.

As a result of this Lansing Smith upgrade, plus other improvement options including the NFRC, the Escambia CC was then no longer selected as a cost-effective option at the conclusion of the initial Steps 1 and 2 analyses. Therefore, the Gulf (and FPL) system has gotten more economic than was the case when the 2019 DSM Goals analyses were performed. This further supports the decision to not examine additional DSM as a resource option when DSM was not projected to be cost-effective even before system improvements such as this CC upgrade began to be made.

Q. This first example focused on fixed costs. Did these analyses also identify ways to lower variable costs?

A. Yes. For an example of how the current Steps 1, 2, and 3 analyses resulted in a projection of lower variable costs, I turn to FPL's response to CLEO/Vote Solar's Second Set of Interrogatories, number 118. Part of this discovery request asked for a projection of system fuel savings from the Steps 1, 2, and 3 analyses. FPL's response to that portion of this interrogatory was that the Steps 1, 2, and 3 analyses were projected to save approximately $1.7 billion CPVRR in fuel costs alone.

Therefore, the FPL/Gulf integrated system is also projected to become significantly more economic in regard to fuel costs. This again supports the decision to not examine already non-cost-effective DSM when the new utility system on which DSM would be evaluated was projected to become significantly more efficient and economic.

Q. Witness Wilson's testimony included a recommendation that FPL incorporate its currently approved DSM goals for 2020 through 2024 into its load forecasts through its long-term planning horizon (Page 8, lines 1-3). Do you agree with this recommendation?

A. No. In responding to this, let's first step back and recall what the FPSC actually did in the 2019 DSM Goals docket. At the start of that process, the FPSC's intent was to set DSM goals for the next 10 years, *i.e.*, for the years 2020 through 2029. This setting of goals for 10 years is what had been done in all prior DSM Goals dockets dating back to 1994. However, after seeing extensive testimony and analysis from all of Florida's utilities that the cost-effectiveness of DSM was steadily declining[10], the FPSC decided to set goals for only 5 years (2020 through 2024), knowing that the goals would be reexamined in 2024. Those goals set through 2024 were essentially to continue the current level of DSM for 5 more years even though most of the current DSM programs were no longer cost-effective.

[10] The fact that DSM cost-effectiveness is declining was not challenged by the intervenor parties in the 2019 DSM Goals docket and has not been challenged by intervenors in this docket.

If the FPSC expressly declined to set goals beyond 2024, based at least in part over concerns over DSM's declining cost-effectiveness, it does not make sense to automatically assume that future Commissions will continue setting non-cost-effective DSM goals for all years in the planning horizon (through 2068). For that reason, I believe witness Wilson's recommendation is unwise. The previously described approach that FPL took in setting DSM assumptions is more consistent with the FPSC's ruling in the 2019 DSM Goals docket.

Q. As part of the intervenors' attempt to turn this docket into a DSM Goals proceeding, do you believe they tried to create an impression that FPL does not value DSM? If so, what is FPL's view of DSM?

A. Yes. However, the impression they are trying to create – that FPL does not value DSM - is inaccurate. To the contrary, FPL has long been an advocate of DSM programs that are cost-effective for all of its customers; *i.e.*, DSM programs that benefit program participants while not putting upwards pressure on electric rates for all customers.

4) <u>The intervenors' unhappiness with the results of FPL's resource planning analyses:</u>

Q. Did the intervenors express unhappiness with the results of FPL's resource planning process and analyses?

A. Yes. And, based on their comments, it is clear that they either do not understand FPL's resource planning process and analyses, or they are simply attempting to criticize the process and analyses because they do not like the results of the analyses.

Q. Please discuss some of the statements the intervenors made regarding FPL's planning process and analyses.

A. Most of the misguided statements made about FPL's resource planning process and analyses were from the testimonies of witnesses Wilson and Rábago. I will start with a few such statements from witness Wilson. The first statement of hers that I will examine is:

"FPL's planning process is biased toward gas-fired resources." (Page 8, lines 6-7).

Q. Does she provide any support for that statement?

A. No.

Q. Is FPL's resource planning group, or its planning process, biased toward gas-fueled resources?

A. No. I have served in FPL's resource planning group continually since 1991 as a supervisor, manager, and now as its director. The guiding principle of FPL's resource planning analyses during that time is that FPL's analyses are agnostic in terms of which resource options are selected. My job, and the job of each member of the resource planning group, is to provide accurate analysis results to FPL management. Consequently, FPL's planning process has no bias toward or against any type of resource option.

Q. If FPL had a bias toward gas resources, one should be able to see evidence of that in FPL's resource plan. Please discuss the changes in generation resources that FPL is actually planning to make for years 2021 through 2030.

A. Figures SRS-7a and SRS-7b below present that information in a graphic format. The information is based on the resource plan that emerged from FPL's current Step 3 analysis results that are presented in detail in my direct testimony. This information also appears in the 2021 FPL/Gulf Ten Year Site Plan. The values shown in the figures account for generating resource additions, upgrades, and retirements which are combined to develop a net nameplate MW addition value for the following generation categories: CC, CT/steam, solar, and battery storage.[11]

Figure SRS-7a first shows the net additions separately for the two types of gas-fueled options, CC and CT/steam. Then Figure SRS-7b combines these two types of gas-fueled options into a singled "gas-fueled" category.

[11] Note that the solar resources being discussed were previously presented in my direct testimony and in FPL/Gulf's 2021 Ten Year Site Plan. These solar additions include: solar being installed in 2021, the planned solar in 2022 and 2023, the SoBRA-based solar additions planned for 2024 and 2025, and all of the 2026-2030 planned solar.

Figure SRS-7a

Net MW Additions by Resource Type: 2021-2030

(w/ separate values for CC and CT/steam)

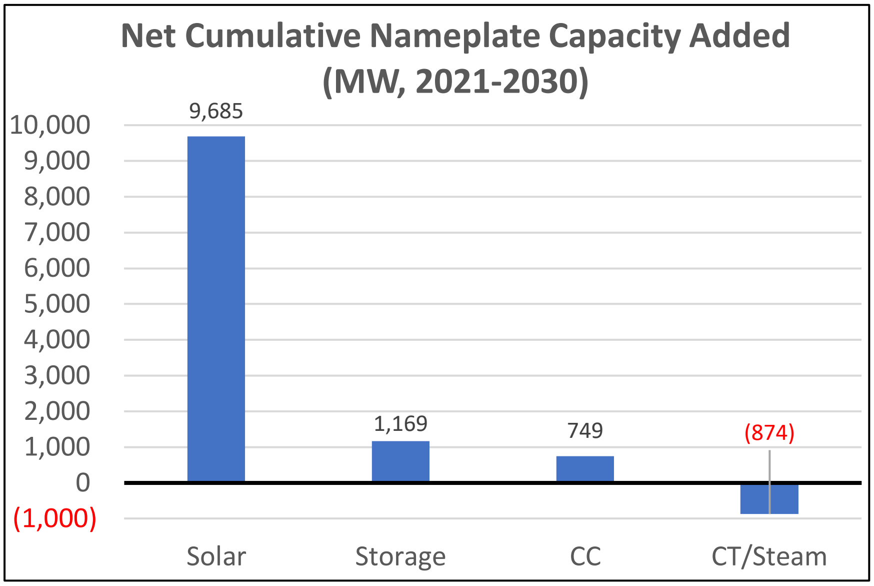
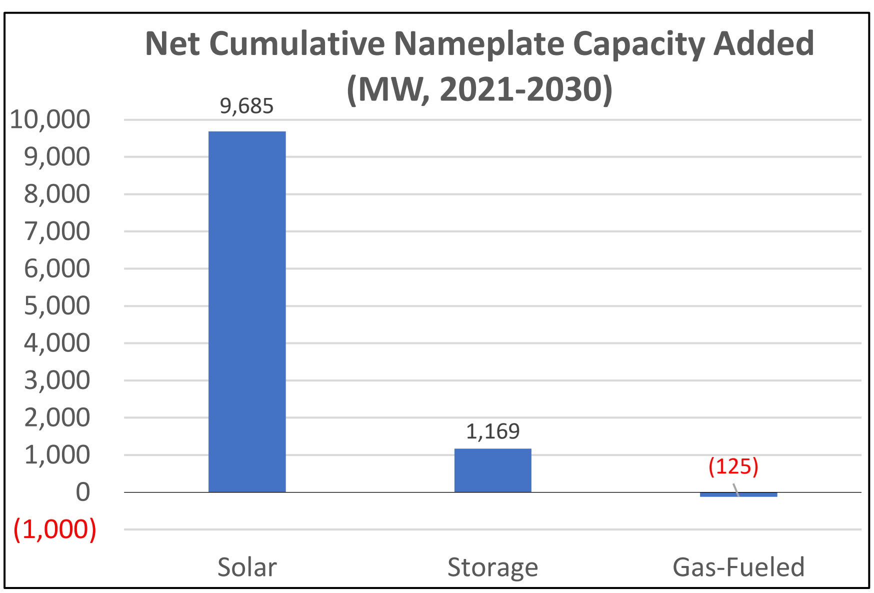


Figure SRS-7b

Net MW Additions by Resource Type: 2021-2030

(w/ a combined value for gas-fueled resources)



It is difficult to look at these values and see why anyone would even try to make a claim that FPL is *"biased"* toward gas-fueled resources as witness Wilson did. (In fact, if one were so inclined - as witness Wilson obviously is - to look for *"bias"* in FPL's resource planning process, one might make a circumstantial argument that FPL is biased <u>against</u> gas-fueled options.)

Q. Because this information used to prepare Figures SRS-7a and 7b is readily available in both the 2021 FPL/Gulf Ten Year Site Plan and in your direct testimony, why do you believe witness Wilson made a statement that was so obviously wrong?

A. I believe it is because this statement fits an objective of her testimony. Witness Wilson, representing CLEO/Vote Solar, had an objective of promoting a view that the only acceptable resource options to add – regardless of the characteristics of the individual utility system in question or system economics – are DSM, renewables, and storage. Having produced no modeling analyses with which she might have questioned the results of FPL's analyses, witness Wilson has taken another approach.

That approach is to simply make statements (such as the inaccurate one just discussed) that attempt to cast aspersions on FPL's motives, then trying to support her favored resource options through comparison methods/metrics (such as the fundamentally flawed $/MWh comparison method) that do not address all of the system impacts of resource options and, for that reason, are not used to make resource planning decisions.

Witness Wilson is not happy with the results of FPL's analyses. Rather than put in the work to present any modeling analyses that might have provided results with which she might meaningfully challenge FPL's analyses, she has decided instead to simply claim that FPL is biased toward resource options that are not her favorites.

Q. Witness Wilson also claimed that FPL did not examine a retirement of the Crist units (Page 15, lines 9-10) and provided little analysis that the coal-to-gas conversion was in the best interest of customers (Page 16, lines 6-7). Do you agree with those statements?

A. No. Although she was not specific, I will assume that witness Wilson's reference to *"Crist Units"* is for Crist Units 6 & 7 only, not for the much smaller (75 MW each) Crist Units 4 & 5 which will be retired soon.

In my deposition, I was asked a question of whether FPL had examined a retirement of Crist Units 6 & 7 and, at that time, I replied that I did not recall if such an analysis had been performed. Witness Wilson chose to take the 'I don't recall' response and then leap to a definitive claim that FPL did not examine a Crist retirement. However, after my deposition, I checked back through the many hundreds of analyses that FPL performed from mid-2018 to the March 2021 filing date in this docket to see if a retirement had been examined. The answer was that FPL had examined that option.

FPL considered the possibility of retiring these two Crist units at two different points in time in its overall analyses. The first consideration came during the initial Steps 1 and 2 analyses. These analyses first focused on Gulf as a stand-alone utility with no new transmission ties to FPL (Step 1), and then as a stand-alone utility which was connected to FPL via the NFRC (Step 2).

Part of the consideration of potentially retiring Crist Units 6 & 7 at that time was a look at how much capacity was already being retired on the Gulf system. A look back at Table SRS-3 in my direct testimony is helpful in this discussion.

That table shows Gulf's generation resources and the percentage each generator's capacity is of the total Gulf generation capacity. Two generation resources comprising 27% (Shell PPA) and 16% (Daniel), which combined represent 43%, of Gulf's total generation were already projected to be retired by the beginning of 2024. And, as shown on both pages of Exhibit SRS-7 in my direct testimony, FPL's optimization model selected either 2 CTs and a 1x1 CC (Step 1), or 4 CTs (Step 2), as the primary replacements for the 43% of Gulf's total capacity that was being retired.

As also shown in Table SRS-3, the Crist Units 6 & 7 together provide approximately 775 MW of generation capacity, or another 24% of Gulf's total generation. If those units were also to be retired, fully 67% of Gulf's generation fleet would be retired and another approximately 700 MW of new capacity would have to be added to Gulf in relatively short order.

However, the retirement of Crist Units 6 & 7 was deemed to be unnecessary for a couple of reasons. First, the coal-to-gas conversion of Crist Units 6 & 7 would not remove any existing capacity (thus requiring no additional new capacity to be added). Second, the conversion was projected to result in significant savings for customers. As shown in Exhibit SRS-7, page 1 of 2, in my direct testimony, the conversion was projected to result in $236 million CPVRR net savings to customers. The conversion project was also one that could be done relatively quickly, thus allowing customers to begin realizing savings more quickly.

Based on these considerations, plus recognition that the cost to replace 700 MW more of retired capacity would be hundreds of millions of dollars, the decision was made to not consider further the retirement of Crist Units 6 & 7 and to proceed instead with the coal-to-gas conversion project. That conversion has now been completed, and customers are already benefiting from it.

Q. Please briefly discuss the second consideration of retiring Crist Units 6 & 7 that occurred at a later point in time.

A. By mid-2019, FPL had completed its early analyses of Step 3 which evaluated the economics of a single, integrated FPL/Gulf system and those results for an integrated system looked promising. Using an integrated system as a starting point, FPL returned to the question of a possible early retirement of Crist Units 6 & 7.

Analyses using the AURORA optimization model were then performed assuming a retirement of the Crist Units 6 & 7 and allowing the model to select from solar, batteries, and gas-fueled replacement options. In these analyses, a trio of CTs (a 3x0 CT) with a total generation capacity of 704 MW was selected by the AURORA model as the most economic choice to replace the retired Crist capacity. The projected additional cost for all 'Crist retirement' cases, was at least $556 million CPVRR more expensive than the 'no Crist retirement' base cases. Based on these results, the early retirement of Crist Units 6 & 7 has been dropped as a potential option for the foreseeable future.

Q. Witness Wilson's testimony states that FPL should have waited before making decisions about certain improvements to the Gulf generation fleet. (Page 17, lines 5-10). Do you agree?

A. No. Witness Wilson seems to believe that if solar is cost-competitive versus CT capacity, then solar should automatically be substituted for the CTs – and FPL should just delay making any decision until solar economics trump CT economics for the Gulf area. Her 'wait-until-we-get-a-certain-answer-we-like' approach is illogical. It fails to account for actual transmission system and operational considerations. The Gulf area currently has only 44 MW of fast start resources: Lansing Smith 3A (32 MW), and Pea Ridge (12 MW). And these small fast start resources are scheduled to be retired soon. A utility needs fast start resources in order to allow the system to be operated reliably.

As previously mentioned, the Crist CTs were first selected for the Gulf area based on economic-only analysis, then discussions that added in the system operations and transmission perspectives confirmed that fast start/longer duration resources (such as CTs) would significantly increase FPL's ability to reliably operate the system as soon as Gulf left the Southern Company system. Thus, Gulf and FPL made the correct decision in 2019 to proceed with acquiring the new CTs.[12]

Q. Do you agree with witness Wilson's claim that batteries could substitute for the CTs selected for the Gulf area (Page 20, lines 6-7)?

A. No, not for the Gulf area. For purposes of this discussion, I will ignore the fact that the comparative economics of these two resource options favor CTs. Instead, I will focus on the capacity, and the duration (length of time) that the capacity can be provided, by each option.

Witness Wilson is correct regarding capacity from an 'academic' perspective, but wrong from the more important 'real world' perspective in regard to the Gulf area. In a reserve margin calculation, a MW of CT capacity, and a MW of battery capacity (whether charged by solar or other sources), can have equivalent value if the full output of the battery can be delivered for at least

[12] In regard to a comment from witness Wilson's about solar prices declining when forecasts are updated, forecasted natural gas prices decreased significantly when the fuel price forecast was updated.

several continuous hours.[13] However, in the real world of system operations, these two resource options are not equivalent in terms of their value during periods of very high load and/or system emergencies that last extended periods of time.

CTs can operate continually for as long as they are needed (and, in recent years, FPL has had to run CTs continually for about 24 hours). But batteries have constraints on the amount of MWh they can produce. Once they have provided their designed amount of energy, they cannot provide any more energy until they are recharged.

Then, the recharging process can become a dual problem, particularly if the utility is still in a very high load/emergency situation when the recharging is needed. First, the 'exhausted' battery can no longer contribute any energy with which to meet load. Second, when the utility attempts to recharge the battery, the recharging battery now becomes an additional electric load that must be served. Furthermore, because batteries have a round-trip efficiency of (roughly) 90%, the battery will require about 100 MWh of charging for every 90 MWh that it can return to the system once it stops becoming another electrical load and starts providing energy. In summary, from an operational perspective,

[13] The needed duration for a battery's maximum hourly capability to be considered as firm capacity varies from utility to utility based, among other factors, on each utility's load shape. All else equal, the longer the needed duration, the more expensive the battery.

especially in a very high load/emergency situation that lasts for an extended period, CTs will typically have more value to system operators.

As previously mentioned, the Gulf area has almost no fast-start/long duration capability which can be used to address very high load or other system emergency. Therefore, from a system reliability and operations perspective, CTs are the logical and correct choice for the Gulf area at this time. Conversely, the FPL area is quite different. The FPL system/area already has a sufficient amount of fast start/long duration capability due to the CTs already on its system. Because of this, FPL is now able to begin using fast start/shorter duration batteries, such as the Manatee battery, to address specific needs. And, as FPL's resource plan shows, with the assumption that the cost of batteries will continue to decline, additional batteries (of relatively short duration) have been selected as cost-effective options in the integrated FPL/Gulf system for the latter years of this decade.

Q. What are examples of misguided statements made by witness Rábago that refer to FPL's resource planning process and analyses?

A. I will first look at two statements of his that pertain to the addition and acceleration of the Crist CTs and the NFRC that show a lack of understanding of FPL's analyses and decisions.

He first states that new CTs were added in the Gulf area due to a new single-contingency risk created by the NFRC (Page 19, lines 1-3). He then claims that the CTs were accelerated forward to mitigate the risk of failure of the NFRC (Page 19, lines 21-22). In making these claims, witness Rábago simply has not grasped the full picture.

New CTs were originally selected as an economic capacity choice for the Gulf system in all of the initial Step 1 and Step 2 analyses. When these resource planning results were then discussed with FPL's system operations and transmission planning groups, those groups strongly supported the selection and indicated that the new CTs would significantly enhance FPL's ability to reliably operate the Gulf area, especially in long duration high load/system emergency conditions.

Those discussions led to the conclusion that not only were the new CTs needed for the Gulf area, but that they needed to be in-service by the time Gulf left the Southern Company system. With almost no existing fast start generation capability in the Gulf area, and no continued committed firm support from Southern Company, it would be difficult to reliably operate the Gulf system/area if either the NFRC, the large Lansing Smith CC unit, and/or the large Shell PPA capacity through mid-2023, was suddenly lost.[14]

[14] I note from reading witness Wilson's testimony that she appeared to understand the fact that the CTs are needed in case of unexpected loss of the NFRC or the large Lansing Smith unit. (See Page 17, lines 1-2)

Therefore, the selection of the CTs was based on economics and supported from a system reliability/operations perspective. The acceleration of the CTs was then necessitated by consideration of at least two potential (longer term) contingencies, the unexpected loss of the large Lansing Smith CC unit and/or the loss of the NFRC connection to FPL.

Q. Witness Rábago claims that CC upgrades (such as at Lansing Smith Unit 3) and the coal-to-gas conversion of Crist Units 6 & 7 as *"costly"* (Page 19, Lines 7-9). Do you agree with this claim?

A. No. After making this claim, he fails to explain: 'costly compared to what?' In my direct testimony, Exhibit SRS-7, page 1 of 2, the Lansing Smith upgrade project was shown to result in a projected $41 million CPVRR net savings and the Crist coal-to-gas conversion was shown to result in a projected $236 million CPVRR net savings.

Perhaps witness Rábago's focus is solely on the installed costs of projects and not on total system net cost impacts. However, sound resource planning accounts for all system costs that are reflected in electric rates when evaluating resource options and resource plans. In combination, the Lansing Smith upgrade and the Crist coal-to-gas conversion are projected to result in a CPVRR net savings for customers of more than $270 million (41 + 236 = 277). From a resource planning perspective, $270 million CPVRR net savings to customers definitely does <u>not</u> equate to the projects being *"costly"*.

Q. Witness Rábago expresses concerns about the volume of plant retirements and what that says about FPL's planning processes and approach to providing low cost service to customers. (Page 21, lines 24-25, and Page 22, line 1) and claims FPL faces no real financial consequences for building new generation that becomes obsolete or uneconomic *"long before the end of their useful lives"*. (Page 22, lines 4-6). Are these concerns well founded?

A. No. This is one of the more baseless contentions he makes. My reaction is that I wonder by what standard witness Rábago attempts to judge what denotes "*long before the end of their useful lives"?* His testimony fails to explain this.

In an attempt to provide a resource planning perspective on the specific generating units that are being retired in the 2021 through 2030 time period (as previously presented in FPL's testimony in this docket, and in the 2021 FPL/Gulf Ten Year Site Plan), Figure SRS-8, shown below, was developed.

Figure SRS-8

Generation Unit Retirements: Years and Capacity Factors

					Projected Capacity Factor									
Unit	Summer Peak Rating (MW)	In-Service Year	Retirement Year	Years in Operation (Yrs.)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Manatee 1	813	1976	2021	45	0.4%	--	--	--	--	--	--	--	--	--
Manatee 2	813	1977	2021	44	0.0%	--	--	--	--	--	--	--	--	--
Scherer 4	636	1989	2022	33	10.4%	--	--	--	--	--	--	--	--	--
Daniel 1	251	1977	2024	47	5.4%	2.0%	0.0%	--	--	--	--	--	--	--
Daniel 2	251	1981	2024	43	3.1%	0.7%	0.0%	--	--	--	--	--	--	--
Crist 4	78	1959	2025	66	7.3%	5.7%	7.1%	8.2%	--	--	--	--	--	--
Pea Ridge	12	1998	2024	26	1.1%	1.3%	1.2%	1.8%	1.3%	--	--	--	--	--
Crist 5	78	1961	2027	66	9.8%	9.1%	9.3%	10.2%	9.2%	9.7%	--	--	--	--
Lansing Smith 3A	32	1971	2028	57	0.6%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	--	--	--

Figure SRS-8 primarily presents two types of information: the age/length of service of the generation resource and the projected capacity factors going forward. In regard to the projected age/length of service, all but two of the generation resources that are planned to be retired will have been in-service for more than 40 years. Included in that list are one generator which will have been in-service for 57 years and two others which will have been in-service for 66 years. The two exceptions are: (i) three very small (4 MW each) Pea Ridge CTs that will be retired after 26 years of service, and (ii) a no longer economic coal unit (Scherer 4) co-owned by FPL that has been operating for 33 years.

In regard to projected capacity factors, only two of the units are projected to operate with a capacity factor of even 10%. The rest of the units have projected capacity factors in single digits. These very low projected capacity factors indicate that these generators are no longer economic to operate on a regular basis due to significant improvements in the operating efficiency of the generation fleet.

Therefore, Figure SRS-8 shows that the generation resources scheduled to be retired are both old and uneconomic to regularly operate. From a resource planning perspective, it would certainly appear that, for these generators, "*the end of their useful lives*" has either arrived or is right around the corner, and that the planning process is working fine in identifying generating units that are ready for retirement.

5) <u>Problems in numerous other statements made by intervenor witnesses:</u>

Q. You have previously commented on some statements witness Rábago made. Are there any other statements he made in his testimony that deserve attention?

A. Yes. Witness Rábago made more statements that deserve comment because they are so remarkably misleading or incorrect. Three of these reflect on his perception of DSM cost-effectiveness tests that can be summarized as follows:

- He claims that the RIM cost effectiveness test is not really a cost-effectiveness evaluation (Page 24, lines 22-23);
- He claims that my direct testimony states that the TRC test does not account for utility costs (Page 24, line 25 and Page 25, lines 1-2); and,
- He claims that the state of Florida treats all energy savings as lost revenues. (Page 26, lines 21-24).

The succinct response to these statements is that each of witness Rábago's claims is wrong (and the explanations for why they are wrong is provided in Exhibit SRS-14).

Q. Did witness Whited make statements in her testimony that are worthy of scrutiny?

A. Yes. The first of these is a claim that I found interesting. Witness Whited claims that vulnerable customers are more likely to have a hard time paying their bills due to higher electric rates (Page 8, lines 11-12). Curiously, her claim is inconsistent with statements made by witness Wilson, who also represents CLEO/Vote Solar and, even more surprisingly, is employed by the same consulting firm, Synapse.

Witness Wilson seems strongly opposed to the RIM cost-effectiveness test for DSM. This test is designed to identify DSM options that will have a more beneficial impact on electric rates[15] compared to a competing supply option. In other words, a DSM option that passes the RIM test is projected to result in a more beneficial impact on electric rates than if the competing supply option were chosen.

Returning to witness Whited's statement above, however, reflects an obvious belief in the value of minimizing electric rates. Because both witnesses are employed by the same company, and represent the same client in this docket, it would seem likely that they reviewed each other's testimony.

Yet neither testimony attempts to reconcile the obvious contradiction of saying (paraphrasing): (i) minimizing electric rates is important, particularly for vulnerable customers, but (ii) don't evaluate DSM options using the only cost-effectiveness test that is designed to identify the option that is best in regard to electric rate impacts. As a result, I found both the contradiction in their

[15] A more beneficial impact means a greater reduction, or a lower increase, in electric rates.

testimonies, and the omission of any attempt by the witnesses to reconcile the contradiction, interesting and concerning.

Q. Are witness Rábago's statements urging the FPSC to reject FPL's proposal to reduce the monthly incentive payment to CDR and CILC participants needed to return the programs to cost-effective status, and to order FPL to aggressively increase program enrollment (Page 25, lines 15-17), consistent with his concerns about the energy burden for Florida households (Page 26, lines 17-19)?

A. No. Witness Rábago's first tells the FPSC that it should not lower the incentive payments to return a non-cost-effective DSM program to cost-effective status, then it should *"aggressively"* sign up more participants using the current non-cost-effective monthly payments. The result of doing so will be to further increase ECCR clause charges and put even more upwards pressure on electric rates for all customers, including the very customers he expresses such concern for. These energy burdened customers, and FPL's other customers who are not participants in the CDR and CILC programs, would then be subsidizing – to an even greater extent than they are now – the large commercial/industrial customers who are CDR and CILC participants.

Q. Witness Whited claims that *"a key reason"* for electricity usage being high in FPL's service territory, compared to customer usage at other utilities, is the level of utility investment in energy efficiency. (Page 19, lines 7-10). Does she provide any support for this claim?

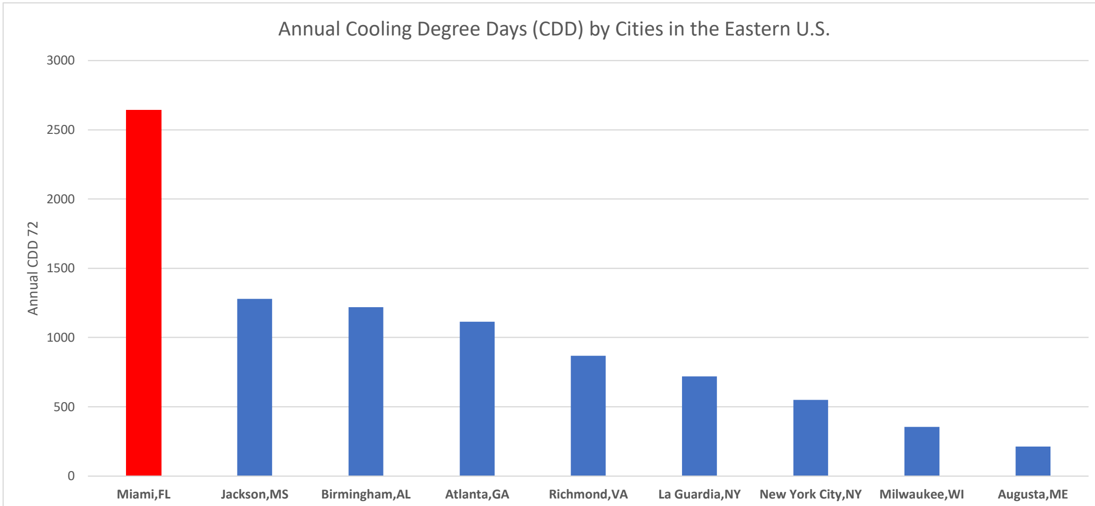
A. No. Witness Whited offers no supporting documentation. One would have thought that her singling out *"utility investment in energy efficiency"* as *"a key reason"* for higher usage meant that she had performed a comparative analysis of the major drivers of load at FPL and other utilities. If she has not done such an analysis, it is hard to see how she can credibly designate utility energy efficiency - or any other factor - as *"a key reason"* for the level of usage by FPL's customers.

For example, how large a "driver" of FPL's load is the amount of cooling degree days ("CDD")[16] that customers face each year in FPL's service territory? To see how much CDD values vary from one utility to another, Figure SRS-9 below compares CDD values for Miami versus a number of cities in the Eastern U.S. that witness Whited presents in an exhibit in her testimony. The reported values are for the years 2016 through 2020.

[16] Cooling degree days ("CDD") essentially measure how hot the air temperature is. It is calculated on an annual basis by subtracting 72 degrees from the average daily temperature for each day, then summing those daily differences for the entire year. CDD can be considered an indication of the total air conditioning or cooling load for a customer or a utility.

Figure SRS-9

Comparison of Cooling Degree Days in Cities in the Eastern U.S.[17]



As indicated in the figure, Miami (and FPL's service territory) has a very high CDD value; *i.e.*, it has a much higher annual cooling load compared to the other areas shown. Even comparing the values for FPL's area only to areas in the notably hot and humid Southeastern U.S. (such as Jackson, Birmingham, and Atlanta), FPL's cooling load is higher by a factor of about 2.

Witness Whited would need to have conducted analyses of all of the main drivers of electrical load for different utilities, including CDD values, before a claim such as the one she made could be supported.

[17] The source of this CDD data is https://www.degreedays.net.

Q. Witness Wilson discussed "stranded assets" in her testimony and claimed that new and existing gas plants are likely to become stranded assets (Page 26, lines 9-13). Do you agree?

A. No. Her testimony indicates she is aware of, and acknowledges, the high level of uncertainty that underlies any discussion of gas units becoming stranded assets. And, as previously explained in the discussion of why CTs were selected for the Gulf area, resource options are not evaluated solely on the basis of economics, but also based on considerations of system reliability and system operation.

Furthermore, as discussed in FPL witness Valle's direct testimony, FPL is planning to test the ability of a CT component of an existing CC unit to utilize solar-generated hydrogen as a fuel in a pilot facility planned to go in-service in late 2023. If the lessons learned from the construction and operation of the hydrogen pilot ultimately lead to a conclusion that existing CC units can be successfully converted to utilize renewable energy-generated hydrogen, then possible concern over a long and useful life for CC units will have been minimized or eliminated.

III. CONCLUSIONS

Q. Would you please summarize your review of the intervenor witnesses' testimony?

A. Yes. I summarize my review of their testimonies by noting the intervenor witnesses:

- Did not perform any modeling analyses of the FPL, Gulf, and/or integrated FPL/Gulf systems in an attempt to support their statements and recommendations;
- Did attempt inappropriately to turn this docket into a DSM goals proceeding; and,
- Did make many inaccurate, misleading, and/or contradictory statements in their testimonies.

As a result, I conclude that these witnesses have no credibility for the purposes of this docket. As a result, their recommendations in this docket should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Matthew Valle was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MATTHEW VALLE

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Matthew Valle. My business address is Florida Power & Light Company, 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" or the "Company") as the Vice President of Development at FPL.

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

A. I am responsible for leading new generation development for the company across technologies including solar, batteries, electric vehicles ("EVs"), hydrogen and natural gas. I have been in this role since November 2015.

Q. Please describe your educational background and professional experience.

A. Prior to my current role, I was Vice President of Development at NextEra Energy Transmission where I was responsible for the competitive development of transmission across the U.S. and Canada. Prior to joining NextEra Energy, I held the position of Principal with The Boston Consulting Group in its Dallas office from 2007 to 2011. In this role, my responsibilities included running project teams for Fortune 500 clients in the energy and technology sectors. Prior to The Boston Consulting Group, I served five years as a nuclear submarine officer in the U.S. Navy. I received a Bachelor of Science with Merit from the U.S. Naval Academy in Systems Engineering and a Master of Business Administration from Harvard Business School.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- MV-1 Consolidated MFRs Sponsored or Co-sponsored by Matthew Valle
- MV-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-Sponsored by Matthew Valle
- MV-3 2022 and 2023 Solar Projects Details
- MV-4 Layout of Major Solar Center Equipment Components
- MV-5 Property Held for Future Use
- MV-6 Electric Vehicle Pilots
- MV-7 Battery Storage Pilot
- MV-8 Green Hydrogen Pilot

I am co-sponsoring the following exhibit:

- REB-12 Solar Base Rate Adjustment Mechanism, filed with the direct testimony of FPL witness Barrett.

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

A. Yes. Exhibit MV-1 lists the consolidated MFRs that I am sponsoring and co-sponsoring.

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. Yes. Exhibit MV-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. What is the purpose of your testimony?

A. My testimony addresses new solar generation projects that will be put into service between 2022 and 2025, building on the success of FPL's solar programs to date. For 2024 and 2025 solar projects, I describe the proposed cost recovery mechanism, a Solar Base Rate Adjustment ("SoBRA"), that is a part of the Company's proposed multi-year rate plan. I also address property held for future use in connection with FPL's generation planning and development. Finally, my testimony addresses investments made and to be made under several pilot programs including EV charging pilots, battery storage pilots, and a new green hydrogen pilot project at our Okeechobee Clean Energy Center.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. When discussing operations or time periods prior to January 1, 2019 (when Gulf was acquired by FPL's parent company, NextEra Energy, Inc.), "FPL" and "Gulf" will refer to their pre-acquisition status, when they were legally and operationally separate companies. For operations or time periods between January 1, 2019 and January 1, 2022, "FPL" and "Gulf" will refer to their status as separate ratemaking entities, recognizing that they were merged legally on January 1, 2021 and consolidation proceeded throughout this period. Finally, operations or time periods after January 1, 2022 are referred to as FPL only, because Gulf will be consolidated into FPL. Therefore, unless otherwise noted, my testimony addresses requests for the consolidated company.

Q. Please summarize your testimony.

A. Since its last rate case in 2016, FPL has continued to lead the state in the development of clean, cost-effective solar generation. FPL leads the industry as the largest owner-operator utility of large-scale solar projects and is currently Florida's largest generator of solar power – operating 33 solar power plants (representing approximately 2,345 MW of large-scale solar capacity). Building on that success, FPL proposes to continue the expansion of solar in its generation fleet by adding an additional 2,980 megawatts of cost-effective solar for the period from 2022 through the end of 2025. In addition to its efforts in deploying fuel-free solar generation since its last rate case, FPL also has been a leader in battery storage applications that have provided and will continue to provide FPL information on how batteries can further increase the performance of FPL's grid and the deployment of renewable energy. Further, FPL has been engaged in piloting EV programs that have allowed and will continue to allow FPL to efficiently plan, adapt and react to the growing use of electric vehicles by our customers. Finally, and consistent with FPL's track record as a leader in innovative technologies that benefit our customers, FPL is seeking approval of a "green hydrogen" pilot project that will allow FPL to test the use of hydrogen as a fuel for its natural gas-powered combined cycle unit at the Okeechobee Clean Energy Center. This exciting new pilot will test FPL's ability to produce hydrogen from water to be used as a fuel source in our combustion turbines at Okeechobee, while at the same time emitting only clean oxygen into the air as a byproduct of the process. In summary, FPL's innovative and effective deployment of solar generation; battery storage pilots; EV pilots; and new green hydrogen pilot program will all continue to benefit FPL's customers and continue to make Florida a national leader in clean, renewable, and innovative technologies.

II. NEW SOLAR GENERATION

Q. In general, what is the current state of solar power generation in Florida?

A. Constructive regulatory policies, such as the approval and implementation of the SoBRA mechanism, has put Florida in a leadership position in new solar development. For FPL, this includes the successful construction of 223 MW_{AC} of solar in 2016, and 1,192 MW_{AC} of solar facilities under the SoBRA cost recovery mechanism approved by the Commission in Order No. PSC-16-0560-AS-EI. Implementing the SoBRA-based solar program resulted in significant cumulative present value revenue requirements ("CPVRR") savings to customers ($172 million); the creation of 3,200 construction jobs; and over $27 million paid in property taxes through 2020. Further, FPL's SolarTogether community solar program was approved by the Commission in 2020 and is on track to provide an additional 1,490 MW_{AC} of solar to the state. Today, Florida ranks fourth in the nation for installed solar, up from ranking ninth in 2016. In addition, at its current pace, Florida is forecasted to claim the number three spot by 2023.

Q. Would you please describe the solar generation projects that the Company plans to address through its four-year base rate plan?

A. Yes. In 2022, the Company plans to place 447 MW_{AC} of solar energy into service by building 6 new solar facilities throughout Florida. In 2023, the Company plans to place an additional 745 MW_{AC} of solar energy into service via 10 more new solar facilities. Details on each of the facilities planned for 2022 and 2023 are contained in Exhibit MV-3 to my testimony. As referenced in the testimony of FPL witness Bores, the revenue requirement associated with the planned solar generation scheduled to be in service in 2022 and 2023 is reflected in the filed MFRs and cost of service for each of those years.

In 2024 and 2025, the Company currently plans to place an additional 1,788 MW_{AC} of solar energy into service. As discussed by FPL witness Barrett, cost recovery for these projects is an essential element of FPL's multi-year rate plan and, at a later date, will be requested via a SoBRA mechanism that is similar to the mechanism approved by the Commission in Order No. PSC-16-0560-AS-EI. I discuss this proposed mechanism in further detail later in my testimony, and it is also addressed in the testimony of FPL witnesses Fuentes and Cohen.

Q. What witnesses discuss the proposed solar energy centers that will be placed into service in 2022 and 2023?

A. In his direct testimony in this matter, FPL witness Sim provides details on the cost-effectiveness of these solar energy centers. In my testimony, I provide operational details for the proposed solar sites for 2022 and 2023 that are included in Exhibit MV-3 to my testimony.

Q. What about the solar that the Company is proposing for 2024 and 2025?

A. Like the solar energy centers slated for 2022 and 2023, FPL witness Sim's Exhibit SRS-12 shows that 894 MW_{AC} of solar is currently projected as a cost-effective resource addition in each of the years 2024 and 2025. My testimony discusses the operational parameters and process proposed by the Company for SoBRA additions in 2024 and 2025.

Q. Please describe FPL's experience designing and constructing solar generation.

A. FPL's extensive experience in designing and building universal solar generation facilities places it among the leaders in the U.S. Since 2009, FPL has completed 33 universal solar centers totaling approximately 2,344 MW_{AC}. The existing FPL universal solar energy centers range in size from 10 MW_{AC} to 74.5 MW_{AC}. These 33 PV universal solar energy centers were constructed and placed into service an average of 7 days early at a total cost of $3.2 billion, nearly $107 million below the cumulative budget.[1] By the end of 2021, as the remaining FPL SolarTogether solar sites are placed into service, FPL expects to have 44 universal solar centers in service with total nameplate rating of 3,164 MW_{AC}.

Q. Why are the foregoing factors important to FPL's customers?

A. Over the past five years, FPL has developed a track record of consistently developing solar projects on time and at or under budget, providing our

[1] Additionally, FPL's non-solar generation projects have, on average, come in approximately 5 percent under budget over the last 15 years.

customers with reliable and cost-effective new emissions-free generation. That track record now includes 33 solar projects in 20 different counties across our service area. Our process starts with early site identification and due diligence and leverages the expertise of our internal team as well as local planners and other consultants to determine whether a site is suitable for future solar construction and to understand local stakeholder issues. Addressing concerns and working to problem-solve in advance can save difficulties later in the permitting or construction process. FPL also works closely with national, state and local organizations from early stages of design and development, and through the operational life of the plant, to determine suitability of prospective solar sites and to ensure compatibility with the surrounding area.

Q. Please describe how FPL's integrated approach to monitoring and optimizing solar fleet performance benefits customers.

A. FPL has developed and continues to improve advanced monitoring technology and performance analysis tools for its solar energy centers. These tools optimize plant operations, drive process efficiencies, and facilitate the deployment of technical skills as demand for services grows. For example, the Company's Fleet Performance and Diagnostics Center ("FPDC") in Juno Beach, Florida, provides FPL with the capability to monitor every plant in its system. The FPDC uses advanced technology to identify potential problems earlier than traditional detection methods, which allows the operating teams the opportunity to prevent or mitigate the effects of failures. FPL compares the performance of like components on similar generating units and determines how to make improvements, which often prevents problems before they would otherwise occur, resulting in improved service reliability for FPL customers. Live video links can be established between the FPDC and plant control centers to immediately discuss challenges that may arise, thus enabling FPL to prevent, mitigate, or solve problems.

Additionally, in 2017, FPL established a Renewable Operations Control Center ("ROCC") to serve as the centralized remote operations center for all FPL PV solar and energy storage facilities. The ROCC provides a mechanism to efficiently manage daily work activities and ensure effective deployment of best operating practices at all of FPL's renewable energy centers. The FPL team has leveraged these capabilities along with its broad range of experience to develop robust operating plans that deliver high levels of reliability and availability at some of the lowest costs in the industry, as discussed in the testimony of FPL witness Broad.

Q. Please describe the solar PV generation technology that FPL plans to use for the 2022 and 2023 solar projects.

A. The 2022 Project will consist of six individual solar energy centers, each with a nameplate capacity of 74.5 MW_{AC}. The 2023 Project will consist of 10 individual solar energy centers, each with a nameplate capacity of 74.5 MW_{AC}. The 2022 and 2023 Projects will utilize a combination of silicon crystal and thin-film solar PV panels that convert sunlight to direct current ("DC") electricity. In addition, the 2022 and 2023 Projects will consist of a mix of both fixed-tilt and tracking configurations, based on local code requirements. In general, FPL's solar site portfolio is a mix of fixed tilt and tracking technology. All other factors being equal, the use of tracking technology can offer higher generation output as well as a higher firm capacity value. This is especially true for using tracking technology in the Gulf footprint, which benefits from a higher firm capacity value due to the western geographic location as compared to the rest of FPL's service area.

It is important to note however that not every location within Florida is currently suitable for the use of trackers. Tracker technology as designed today provides more benefit to the customer in areas where the wind loads fall below certain thresholds defined by current wind loading maps or individual site wind load studies. In extremely high wind load environments, the overall cost of the material and labor needed to meet the design criteria for such high wind loads is not cost effective. In addition, tracker technology requires a larger land footprint than a fixed site, which sometimes makes this option infeasible at certain space constrained sites.

The panels for these projects will be linked together in groups, with each group connected to an inverter, which transforms the DC electricity produced by the PV panels into alternating current ("AC") electricity. It should be noted that the inverters will be mounted with a medium voltage transformer on an equipment skid called a Power Conversion Unit ("PCU"). The voltage of AC electricity coming out of each inverter is increased by a series of transformers to match the transmission interconnection voltage for each solar center.

FPL used baseline designs to establish the cost and performance projections for the centers, and FPL continues to evaluate potential optimization opportunities as work moves forward. Design optimization activities review the type of support system and selection of other major components to ensure high yields of output, availability and reliability, and the highest overall benefit to the customer. Details of the final designs for the solar centers would differ from the baseline only if such changes result in a greater benefit to FPL's customers. Exhibit MV-4 provides a typical block diagram depicting the basic layout of major equipment components.

Q. What are the proposed commercial operation dates for the 2022 and 2023 Projects?

A. As reflected in more detail in Exhibit MV-3 to my testimony, the 2022 Project started construction activities in December 2020. For the 2023 facilities, the projects are expected to begin construction in mid-2021. The period necessary to complete engineering, permitting, equipment procurement, contractor selection, construction, and commissioning is typically between twelve and eighteen months. This construction period includes the time necessary to prepare each of the sites, construct roads and drainage systems, install the solar generating equipment, erect fencing, and build the interconnection facilities. The construction schedules support the proposed commercial in-service dates.

Q. What is FPL's estimated cost for the 2022 and 2023 Projects?

A. FPL estimates that the total cost of the 2022 Project (6 sites) will be $560 million, at an average price of $1,254/kW$_{AC}$. The 2023 Projects (10 sites) are projected to cost $916 million, at an average price of $1,229/kW$_{AC}$. The 2022 and 2023 Projects are expected to deliver a total of $397 million in CPVRR savings to our customers, as demonstrated by FPL witness Sim.

Q. Are the cost estimates for equipment, engineering, and construction for the proposed solar generation reasonable?

A. Yes.

Q. What is the basis for your conclusion?

A. The selected solar sites for the 2022 Project and 2023 Projects are well into permitting and have undergone extensive diligence. Thus, we have confidence that we will be able to construct them on-time and on-budget. Further, the costs for all surveying, engineering, equipment, materials and construction services necessary to complete the centers have been established through competitive bidding processes specific to the 2022 and 2023 Projects, ensuring that 100% of the project costs for procurement of construction goods and services are subject to competitive solicitation.

Q. Please describe the competitive solicitations associated with the 2022 and 2023 projects.

A. Like prior SoBRA projects, FPL followed a similar process for procurement of equipment and contractors for the 2022 Project. This includes having solicited proposals for the supply of the PV panels, PCUs, and step-up transformers, as well as the engineering, procurement and construction services required to complete the proposed solar energy centers. FPL requested proposals from industry leading suppliers for the procurement of PV panels, inverters, PCUs, and step-up transformers, as well as the engineering, procurement and construction ("EPC") services required to complete the proposed solar energy centers for the 2022 Project.

FPL requested proposals for PV panels from nine large, industry-leading suppliers. Six suppliers submitted bids that satisfied the requirements of the request for proposals ("RFP"). The six conforming bids were evaluated. In addition to offering the lowest cost and highest efficiency, the selected supplier has demonstrated that they have among the highest product quality programs in the industry and was able to provide strong financial performance security.
FPL solicited proposals from six PCU suppliers. All the proposals met the requirements of the RFP and the award was made to a single supplier. Further, the solicitation for the step-up transformers has been completed. FPL solicited proposals from six industry-leading manufacturers of step-up power transformers and secured the supply of the required transformers from the best evaluated as well as the lower cost bidder.

EPC service proposals for the Projects were solicited from six industry-recognized contractors. Four of the six contractors submitted bids and the proposals were evaluated. FPL has finalized a contract with the EPC contractor that submitted the best proposal for the construction of the 2022 Project. The scope of services for the EPC solicitations included the supply of the balance of equipment and materials. Proposals for the construction of the substation and interconnection facilities will be solicited from industry-recognized contractors. Bids will be evaluated for the requirements of the proposal, and the best bidder will be selected to construct the substation and interconnection facilities. A similar competitive procurement process is being followed for the 2023 Projects in mid-to-late 2021.

Q. Can you describe how FPL acquired the property for the 2022 and 2023 Projects?

A. Yes. FPL screens candidate parcels by using criteria including each property's proximity to a transmission system interconnection point, availability of transmission capacity, and assessment of whether the property provides sufficient acreage to accommodate the expected permitting requirements and the construction of the solar centers. FPL evaluates the features of each property as a whole for factors such as the presence of wetlands and flood plains, environmental constraints, and cultural restrictions, and FPL develops designs that optimize the land use for each parcel. In addition, FPL also reviews its land portfolio to ensure that the site development timeline is in line with expected in-service dates for the Projects.

Q. Do FPL's cost estimates include the costs associated with transmission interconnection?

A. Yes. The estimated capital construction cost for each of the projects includes the projected cost for its unique interconnection configuration.

Q. Are upgrades to the existing FPL bulk transmission system required to accommodate the proposed solar energy centers?

A. No network upgrades to FPL's bulk transmission are required and, as a result, there are no costs associated with transmission system upgrades. Any incremental capital costs resulting from affected system impacts and upgrades are covered in capital cost projections.

Q. Are there other benefits associated with the 2022 and 2023 Projects?

A. Yes, there are several other benefits associated with the projects. For example, approximately 200 individuals will be employed at each of the centers at the height of construction, creating about 1,200 jobs for the 2022 Project and approximately 2,000 jobs for the 2023 Projects. The contractors building the solar energy centers are required to exercise reasonable efforts to use local labor and resources. The jobs associated with the construction of the centers will therefore provide a secondary benefit by boosting the economy of local businesses. Additionally, the local communities will benefit from increased property tax revenues following the completion of the solar energy centers. For instance, prior FPL SoBRA projects resulted in over $27 million in property taxes paid through 2020.

Q. How does the Company propose that the SoBRA mechanism for the years 2024 and 2025 will operate?

A. This process is detailed in FPL witness Barrett's exhibit REB-12. In summary, FPL is proposing that the SoBRAs in 2024 and 2025 operate consistent with the methodology approved in Order No. PSC-16-0560-AS-EI and FPL's previous SoBRA filings in Docket Numbers 20170001-EI, 20180001-EI, and 20190001-EI. FPL would file a request for cost recovery approval of the solar generation project at the time of its final true-up filing in the Fuel and Purchased Power Cost Recovery Clause docket in the year prior to the solar generation project going into service. In that proceeding, as with prior SoBRA proceedings, the Commission will determine whether the solar project lowers FPL's projected CPVRR compared to the projected system CPVRR without the project, and the amount of revenue requirements and appropriate percentage increase in base rates needed to collect the estimated revenue requirements. The method of calculating revenue requirements for the 2024 and 2025 SoBRAs is described in the testimony of FPL witness Fuentes and FPL witness Cohen describes the associated adjustment in rates and riders. If the solar project is approved, FPL will calculate and submit for Commission confirmation the amount of the SoBRA for each such solar project using the annual Capacity Clause projection filing for the year that solar project is scheduled to go into service. As explained by FPL witness Cohen, base rates then would be adjusted consistent with that amount upon commercial operation of the respective solar project(s).

In the prior multi-year plan, there were limitations on the amount of solar megawatts that can be recovered through the SoBRA mechanism as well as

$/kW$_{AC}$ price limits[2] for the projects. For the 2024 and 2025 SoBRAs, FPL is proposing a $1,250/kW$_{AC}$ recovery cost cap, or roughly 30% ($500/kW$_{AC}$) below FPL's 2016 SoBRA cap of $1,750/kW$_{AC}$. Further, FPL proposes a "not to exceed" SoBRA limit of 1,788 MW$_{AC}$ for 2024 and 2025 combined, with no more than 894 MW$_{AC}$ for 2024, as reflected in FPL witness Sim's Exhibit SRS-12[3].

III. PROPERTY HELD FOR FUTURE USE

Q. Can you please describe what property the Company is holding to develop solar and other generation projects in the future?

A. Yes. Exhibit MV-5 to my testimony shows property that the Company is holding for future solar and other generation project development, as of December 31, 2020.

Q. Did the Company reasonably and prudently acquire these sites for future generation facility development?

A. Yes. Exhibit MV-5 to my testimony provides details on each site held for future use. Each of these properties will be evaluated for use with the 2024 and 2025 solar projects that I discussed earlier in my testimony.

[2] FPL may also have the ability to deploy some of the 2024 and 2025 SoBRA projects with battery storage and would seek to do so as long as the total project cost cap was not exceeded, and so long as solar plus storage was cost effective versus solar alone.
[3] FPL also requests the ability to carryover any megawatts that do not come into service in 2024 into 2025.

Q. Does the property that you are holding for future solar use align with the assumptions for solar generation facilities that will be needed in the future?

A. Yes. FPL's most recent Ten-Year Site Plan identified a total of 6,854 MW_{AC} of new solar additions between 2022 and 2029 – roughly ninety-two (92) new solar energy centers. As a consequence of this shift in generation mix and the increasing levels of solar generation, there will be a commensurate increase in utility property held for future use balances to meet future resource needs. Given the continuing development pressure within the state of Florida, it is prudent to acquire land now to ensure that FPL can cost effectively meet these future resource planning needs. Increases in the amount of land set aside for conservation areas combined with ongoing residential and commercial development pressure means that finding and obtaining land suitable for future solar sites will become more difficult and ultimately will be more expensive. All these elements contribute to reducing the overall amount of available, suitable land in Florida making it increasingly important to identify, acquire, and obtain the necessary permits for future solar sites. A key component of FPL's success in solar development hinges on the early execution of a land acquisition plan in recognition of the underlying macroeconomic conditions and development constraints noted above.

Suitable land must possess very specific locational and environmental attributes, including factors such as: (1) non-residential land, preferably agricultural; (2) land close to existing FPL transmission lines with available injection; (3) land screened for minimum wetlands, species, and other environmental impacts; (4) large land parcels with one owner (if possible) to reduce the administrative burden to develop land with various owners; and (5) land dispersed throughout FPL's service area.

Finally, FPL's preferred process is to enter into purchase options with landowners to minimize upfront purchases and allow the opportunity for better alignment of the purchase of the land with the development timeline. However, there are instances where landowners will not enter into options, in which case, as explained above, FPL evaluates the site benefits and decides whether to purchase the land.

IV. PILOT PROJECT PROGRAMS

Q. What investments made in conjunction with the pilot projects are you sponsoring?

A. In Exhibit MV-6 to my testimony, I detail certain investments that have been made to effectuate EV Pilots and, in Exhibit MV-7 to my testimony, I describe the investments made under the Battery Storage Pilot that the Commission approved in Docket 160021-EI. My testimony demonstrates that the EV investments are reasonable and prudent expenditures and that the battery storage projects meet the standard for prudence in Order No. PSC-16-0560-AS-EI.

Q. Please discuss the investments made for EV Pilots.

A. FPL began implementation of the new FPL EVolution pilot program in 2019 to support the growth of EVs with the goal to install more than 1,000 charging ports. The primary objective of this pilot program for FPL is to gather data and learnings ahead of mass EV adoption to ensure future EV investments enhance service and reduce costs. The FPL EVolution Pilot focuses on three key areas: a) infrastructure build-out impacts of EV adoption rates; b) rate structures and demand models; and c) grid impacts of fast-charging.

Installations under the pilot encompass different EV charging technologies and market segments, including level 2 workplace and fleet charging at public and/or private workplaces; destination charging at well-attended locations; residential charging at customers' homes; and DC fast charging in high-traffic areas like bus depots and strategically-located sites along highway corridors and evacuation routes. This pilot program is conducted in partnership with interested host sites. Exhibit MV-6 to my testimony provides a breakdown of ports, charger types and market segments; but the number of charging ports and segmentation will be dependent on final site selection.

FPL anticipates the Company's total investment in the FPL EVolution pilot program to be $30 million through the end of 2022, which has been included for base rate recovery as part of this proceeding. A portion of this investment will be offset by any revenues received under FPL's UEV tariff. The UEV tariff, approved by the Florida Public Service Commission in Docket Number 20200170-EI, establishes a rate for utility-owned public EV fast charging stations. The UEV tariff enables FPL to charge drivers directly at certain FPL EVolution fast charging stations. The UEV tariff took effect in January 2021 and will last for a period of five years.

Q. Please discuss the investments made under the Battery Storage Pilot that the Commission approved in Docket 160021-EI.

A. FPL was authorized in Order No. PSC-16-0560-AS-EI to deploy up to 50 MW_{AC} of battery pilot projects to analyze the future potential of battery storage technology. FPL has invested in ten separate projects as part of the 50 MW_{AC} pilot. Each project is designed to provide unique learnings on how the battery and the system operate as reflected in Exhibit MV-7. For example, two of the storage pilots involved pairing battery storage with existing universal PV facilities, designed to capture curtailed (or "clipped") solar energy from the solar panels during high solar insolation hours and release the energy in other hours. Other pilots were designed to shift PV output from non-peak times to peak times and to provide "smoothing" of solar output and regulation services. The data and lessons gathered from these pilots have resulted in more optimized design configurations for solar-paired battery projects as well as improved operational parameters for economic dispatch. Additional projects include: deploying a 10 MW_{AC} battery in a dense urban area to examine the use of batteries to support the distribution system; deploying a battery alongside an existing solar PV system to create a micro grid; Electric-Vehicle-to-Grid

("EV2G") batteries using electric school buses that will be able to discharge electricity to the grid when needed; and deploying a battery at the Dania Beach Clean Energy Center Unit 7 to provide an opportunity to test using battery storage for black start capability of large generating units. FPL is also developing a battery augmentation pilot at existing battery storage locations to evaluate battery degradation and evaluate various solutions. As reflected in exhibit MV-7, each of these pilot projects are at or under the \$2,300/kW_{AC} cost cap in FPL's 2016 settlement agreement.

Q. Earlier in your testimony, you mentioned a new "green hydrogen" pilot project at the Okeechobee Clean Energy Center ("OCEC"). Please explain what is meant by "green hydrogen" and provide a summary of this proposed pilot project.

A. FPL is constantly searching for ways to integrate state-of-the-art technologies that will further enhance the diversity of clean energy solutions that benefit our customers. FPL's recently announced hydrogen pilot project is a further example of how the Company is incorporating innovative technologies to help usher in the next era of Florida's clean energy future. As the use of solar energy increases in the future, there may be times when solar production will need to be curtailed to accommodate electric grid load requirements. Rather than curtailing that solar energy production, it could be possible for that energy to be rerouted to produce what is known as "green hydrogen" that can be stored as a fuel for combustion turbine power generators. This proposed pilot would allow FPL to assess how our combustion turbine units operate with a hydrogen fuel mix and also will allow us to learn how a hydrogen fuel production and storage facility can be effectively used on site with combustion turbine units. With minor modifications, we believe that the existing combustion turbine units at the Okeechobee site could operate on a fuel blend of up to 5% hydrogen and 95% natural gas. Expected learnings from this pilot include lessons from design, procurement, construction, commissioning, operations, and maintenance during a variety of operational scenarios on the grid. With the addition of the hydrogen, less natural gas will be needed for the combined cycle unit to produce power; the total carbon dioxide ("CO_2") emissions of the unit will be reduced; and fuel diversity will be increased, which can help mitigate the impacts of supply shortages and disruptions.

To provide a source of hydrogen to burn for this pilot, FPL proposes to build an approximate 25 MW electrolyzer and a storage facility for the production and on-site storage of hydrogen at Okeechobee. The electrolyzer would be interconnected with generation at the Okeechobee site so that electrical energy can be used in the electrolyzer to separate water into hydrogen and oxygen gases. The oxygen is released into the air while the hydrogen is compressed and stored on-site where it can later be used as fuel in the combustion turbine units at the Okeechobee site. A graphic representation of the configuration of this equipment is included in Exhibit MV-8 to my testimony.

Q. When would this Hydrogen Pilot be placed into service and what is the estimated project cost?

A. If approved in this case, FPL estimates that the pilot project can be put in service in 2023 at an estimated cost of $65 million.

Q. Is this Hydrogen Pilot a reasonable and prudent investment?

A. Yes. FPL continues to look for ways to provide clean, reliable, and affordable energy. Similar to our previous approach on battery storage and solar energy, we are starting with a small proposed pilot program to gain knowledge. Part of that effort is to search for ways to integrate state-of-the-art technologies that will further enhance the diversity of clean energy solutions that benefit our customers. Hydrogen power is part of that vision moving forward and could, in the long term, help us reduce our carbon footprint and provide reliable, cost-effective and carbon-free energy. This project is a first step in learning about how hydrogen technology can benefit customers and potentially help unlock a day when electricity is 100% carbon free. Given the relative small scope of the pilot compared to the size of FPL's fleet and the wealth of data and information that FPL can obtain from this pilot, along with the exciting possibilities that this project could offer for the future, the proposed pilot is a reasonable and prudent investment for FPL's customers.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Matthew Valle was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF MATTHEW VALLE

DOCKET NO. 20210015-EI

JULY 14, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Valle, and my business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you co-sponsoring or sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- Exhibit MV-9 Property Held for Future Use – Forecasted COD

I am co-sponsoring the following exhibit:

- LF-10 FPL's Notice of Identified Adjustments filed May 7, 2021 and Witness Sponsorship, filed with the rebuttal testimony of FPL witness Fuentes.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I address contentions made by OPC witness Smith regarding property held for future use. I also address arguments made by Florida Rising, *et al*, witness Rábago regarding FPL's proposed green hydrogen pilot.

Q. Please summarize your rebuttal testimony.

A. OPC witness Smith suggests that the Company should provide more detail on properties held for future use that have a "to be determined" in-service date in some discovery documents that he reviewed while preparing his testimony. While it appears that some of the properties that witness Smith discusses are related to transmission and distribution properties that are addressed by FPL witness Spoor in his rebuttal testimony, my testimony provides additional detail on land associated with generation projects that have a "to be determined" in-service date. In addition, my rebuttal testimony also shows that witness Rábago's criticisms of FPL's proposed green hydrogen pilot are unfounded.

II. PROPERTY HELD FOR FUTURE USE

Q. What issues from OPC witness Smith's testimony are you addressing regarding property held for future use?

A. On pages 48-52, witness Smith discusses transmission and distribution properties held for future use and, in summary, states that he has not recommended any disallowances regarding those properties subject to the Company confirming in-service dates for those properties that he found in FPL's FERC Form 1.[1] In addition, witness Smith has raised issues about properties associated with generation projects that have a "to be determined" in-service date reflected in my Exhibit MV-5, which I address in herein.

[1] Smith testimony at page 51, lines 1-3 (discussing transmission and distribution property); page 49, lines 3-19 (discussing properties with a "TBD" in-service date that have in-service dates in FPL's FERC Form 1 and requesting confirmation of in-service dates with no recommended disallowance).

Q. Why do some of the properties listed in your Exhibit MV-5 have a "to be determined" commercial operation date?

A. As I discuss on pages 19-21 of my direct testimony, some of the properties listed on my Exhibit MV-5 have "TBD" or "to be determined" listed for their commercial operation date because FPL does not currently know which of those parcels will be used for FPL's solar projects specifically in 2024 or specifically in 2025. As my direct testimony shows, however, all of the properties listed in my Exhibit MV-5 will be used either for projects identified with FPL's proposed Solar Base Rate Adjustment ("SoBRA") in 2024 and 2025 or will be used for additional solar projects identified in FPL's current Ten Year Site Plan. In Exhibit MV-9 to this rebuttal testimony, I have provided the Company's current view of how those "TBD" parcels from my Exhibit MV-5 would be deployed. In any event, all of the properties on my Exhibit MV-5 either have an in-service date listed in that exhibit or are anticipated to be used within the next few years to support builds identified in FPL's current Ten Year Site Plan, particularly in 2024 and 2025, as my Exhibit MV-9 shows.

III. GREEN HYDROGEN PILOT

Q. What are your conclusions on witness Rábago's criticisms of FPL's proposed Green Hydrogen Pilot?

A. Read in the context of all his testimony, it appears that Mr. Rábago's criticisms are rooted in his dislike for natural gas generation given the fact that FPL's proposed Green Hydrogen Pilot will be tested at scale at a natural gas power plant. Rather than piloting hydrogen at scale as a potential fuel source that could one day repower FPL's entire natural gas fleet with 100% green hydrogen, witness Rábago states that FPL should instead focus on very small distributed energy hydrogen pilots.

Q. Do you agree with witness Rábago's suggestions?

A. No. Mr. Rábago's criticisms and suggestions are the same type of rhetoric that we heard when FPL first piloted large scale solar and large-scale battery projects that have now led the way for mass solar and battery deployments. Had FPL accepted similar arguments to "think small" when it was first piloting solar and battery deployments, FPL would not be where it is today with those technologies. Frankly, I am surprised that a witness testifying on behalf of the Environmental Confederation of Southwest Florida would be opposed to a pilot that could help lead to a carbon-free future for FPL's generation fleet.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 21st day of September, 2021.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024