BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20180149-EI

PETITION FOR A LIMITED PROCEEDING TO APPROVE FIRST SOLAR BASE RATE ADJUSTMENT, BY DUKE ENERGY FLORIDA, LLC.

_____/

VOLUME 2
PAGES 122 through 230

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER JULIE I. BROWN COMMISSIONER DONALD J. POLMANN COMMISSIONER GARY F. CLARK COMMISSIONER ANDREW GILES FAY
DATE:	Tuesday, April 2, 2019
TIME:	Commenced: 10:55 a.m. Concluded: 3:35 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	ANDREA KOMARIDIS Court Reporter
APPEARANCES:	(As heretofore noted.)

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I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID	ADMITTED
7 through 10 - (as identified on the comprehensive exhibit list)		139
11 through 14 - (as identified on the comprehensive exhibit list)		213

P R O C E E D I N G S

(Transcript continues in sequence from Volume 1.)

CHAIRMAN GRAHAM: All right. Duke, your witness.

MS. TRIPLETT: We have Mr. Borsch here, but I also was reminded that Ms. Olivier's testimony and exhibits need to be entered. So, I can do that now, if that's okay.

CHAIRMAN GRAHAM: Yeah.

MS. TRIPLETT: Or do you want to do it at the end?

CHAIRMAN GRAHAM: Let's do that now.

MS. TRIPLETT: Now? So, we would request that the prefiled testimony -- she has two. She has one that was filed on July 31st, and a supplemental filed on August 24th. We would ask that those two testimonies be inserted into the record as though read.

CHAIRMAN GRAHAM: We'll insert those two records into the record as though read -- those two testimonies into the record as though read.

(Whereupon, Witness Olivier's prefiled direct and supplemental testimony was inserted into the record as though read.)

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE FIRST SOLAR BASE RATE ADJUSTMENT

FPSC DOCKET NO. _____

DIRECT TESTIMONY OF MARCIA OLIVIER

JULY 31, 2018

Q. Please state your name and business address.

A. My name is Marcia Olivier. My business address is Duke Energy Florida, LLC, 299 1st Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Director of Rates and Regulatory Planning.

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

A. I am currently responsible for overseeing rate cases, reporting earnings surveillance results, and supporting various regulatory filings and initiatives, including the Company's filing for recovery of its investments in solar projects.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting and a Bachelor of Science degree in Finance from the University of South Florida and have almost 20 years of utility experience, primarily in the regulatory area.

Q. What is the purpose of your testimony?

A. Paragraph 15 of the 2017 Revised and Restated Settlement Agreement ("2017 Settlement") provides for solar base rate adjustments. Specifically, Paragraph 15.c. states:

> Solar generation projects not subject to the Florida Electrical Power Plant Siting Act (i.e., fewer than 75 MW), also will be subject to approval by the Commission as follows: (i) DEF will file a request for approval of the solar generation project in a separate docket; and (ii) the issues for determination are limited to: the reasonableness and cost effectiveness of the solar generation projects (i.e., will the projects lower the projected system cumulative present value revenue requirement "CPVRR" as compared to such CPVRR without the solar projects); the amount of revenue requirements; and whether, when considering all relevant factors, DEF needs the solar project(s). Any Party may challenge the reasonableness of DEF's actual or projected solar project costs. If approved, DEF will calculate and submit for Commission confirmation the base rate adjustment for each such solar project, consistent with Subparagraphs 15.e. and 15.f.

Matthew Stout will present direct testimony describing the solar projects and the reasonableness of the costs, and Benjamin Borsch will present direct testimony demonstrating the cost effectiveness of the solar projects. My testimony will provide

the annualized revenue requirements for these first solar projects. I will also present the process for submitting the customer rate impacts in a subsequent filing.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit No. ___ (MO-1), "SoBRA First Year Annualized Revenue Requirement." This exhibit is true and accurate.

Q. Has DEF calculated the revenue requirements for the solar projects consistent with the 2017 Settlement?

A. Yes. Based on the cost information provided in Mr. Stout's testimony, I have calculated the annualized revenue requirements of the Hamilton Solar Power Plant ("Hamilton Project") to be $15.2 million and the Columbia Solar Power Plant ("Columbia Project") to be $14.0 million as shown in my Exhibit No. __ (MO-1). These amounts have been calculated in accordance with Paragraph 15.f. of the 2017 Settlement, which requires that the revenue requirements be "calculated using a 10.5% ROE and DEF's projected 13-month average capital structure for the first 12 months of operation, including all specific adjustments consistent with DEF's most recently filed December earnings surveillance report, and excluding the treatment of common equity and rate base (working capital) allowed in Paragraph 18 of the 2013 Settlement Agreement, and adjusted to include an ADIT proration adjustment consistent with 26 C.F.R. Section 1.167(l)-1(h)(6) and adjusted to reflect the

inclusion of investment tax credits on a normalized basis." Further, as required by Paragraph 12.c. of the 2017 Settlement, DEF has calculated the revenue requirements using the lower 21% federal income tax rate as a result of the 2017 Tax Cuts and Jobs Act. Given that the solar projects included in the first group have different in-service dates, DEF has calculated the revenue requirements separately. The Hamilton Project has an expected in-service date of December 2018 and a rate effective date of January 2019. The Columbia Project has an expected in-service date of March 2020 and a rate effective date of April 2020.

Q. **Does the 2017 Settlement provide for a true-up mechanism to be applied to SoBRA rates?**

A. Yes. Paragraph 15.g. of the 2017 Settlement states, "In the event that the actual capital expenditures are less than the approved projected costs, included in the petition for cost recovery and used to develop the initial base rate adjustment, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised base rate adjustment will be computed using the same data and methodology incorporated in the initial base rate adjustment, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going-forward basis, base rates will be adjusted to reflect the revised base rate adjustment. The difference between the cumulative base revenues since the implementation of the initial base rate adjustment and the cumulative base revenues that would have resulted

if the revised base rate adjustment had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C." Once the capital expenditures are final, if they are less than the amount approved by the Commission, then DEF will make a true-up filing to reduce base rates going forward and provide a refund through the CCR clause consistent with the provisions in Paragraph 15.g. of the 2017 Settlement.

Q. Has DEF calculated the solar base rate adjustment factor consistent with the 2017 Settlement?

A. Not at this time. DEF has other expected base rate increases at the same time as Hamilton Project's January 2019 base rate increase. DEF has tariff changes currently pending for the Citrus County combined cycle units approved in Docket No. 20180084-EI. DEF will also be filing tariff changes for the multi-year rate increase effective January 2019 pursuant to Paragraph 12.b. and 12.c. of the 2017 Settlement. DEF will calculate and submit for Commission confirmation the uniform percentage increase, base rate customer, demand and energy factors, and the tariff sheets, for the Hamilton Project upon filing the base rate factors for the multi-year increase, but no later than August 31, 2018. Since the Columbia Project will not be completed until early 2020, DEF will submit the uniform percentage increase, solar base rate customer, demand and energy factors, and tariff sheets for the Columbia Project at the earliest appropriate date considering other expected base rate filings prior to the Columbia Project's in-service date.

Q. What is the estimated residential base rate impact of the Hamilton Project?

A. The estimated residential base rate impact is approximately $0.46 on a 1,000 kWh bill. The tariff sheet reflecting the residential base rate impact will be updated and submitted for Commission confirmation with the uniform percentage increase, base rate customer, demand and energy factors, and the tariff sheets, for the Hamilton Project upon filing the base rate factors for the multi-year increase, but no later than August 31, 2018.

Q. **How will DEF notify the Commission of the commercial operation date of each solar facility?**

A. DEF will submit to the Commission a letter that declares the commercial operation date of each solar facility prior to any Solar base rate changes.

Q. Does that conclude your testimony?

A. Yes.

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE FIRST SOLAR BASE RATE ADJUSTMENT

FPSC DOCKET NO. 20180149-EI

SUPPLEMENTAL DIRECT TESTIMONY OF MARCIA OLIVIER

AUGUST 24, 2018

Q. Please state your name.

A. My name is Marcia Olivier.

Q. Have you previously filed testimony in this docket?

A. Yes, on July 31, 2018, I filed direct testimony in support of Duke Energy Florida, LLC's ("DEF" or the "Company") filing of its request for approval of its first solar base rate adjustment.

Q. Have your job position, duties and/or responsibilities changed since you filed your direct testimony?

A. No, they have not.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to sponsor exhibits to explain calculations for the uniform percentage increase, and base rate customer, demand and energy factors for DEF's first solar project (the Hamilton Project described in my July 31, 2018 Direct Testimony) and the multi-year rate increase authorized by

Paragraph 12 of the 2017 Revised and Restated Settlement Agreement ("2017 Settlement"). I also explain and present the tariff sheets that reflect both the Hamilton Project and the multi-year base rate increase. In addition, I provide a summary of tariff changes, presenting multiple scenarios of the combined impacts to customer rates. My testimony and exhibits also include the impact of the base rate increase for Citrus Units 1 and 2, which were approved by this Commission in Docket No. 20180084-EI.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. ___ (MO-2), "Uniform Percentage Increase and Summary of Tariff Changes;"

Exhibit No. __ (MO-3), "Redline Tariff Sheets Reflecting Hamilton Project and Multi-Year Increases;" and

Exhibit No. __ (MO-4), "Clean Tariff Sheets Reflecting Hamilton Project and Multi-Year Increases."

Note that Exhibit No. __(MO-3) and Exhibit No. __ (MO-4) do not bear exhibit labels since they are tariff sheets. These exhibits are true and accurate.

Q. Please explain why your testimony includes details about several different expected rate increases.

A. As I indicated in my July 31, 2018 Direct Testimony, DEF has several expected base rate increases that will go into effect with the January 2019 billing cycle. Those changes include the base rate increase approved by the Commission in Docket No. 20180084-EI for the second Citrus County Combined Cycle Power Block ("Citrus Unit 2"), the multi-year increase authorized by Paragraphs 12.b. and 12.c. of the 2017 Settlement, and the Hamilton Project. However, two of those expected rate increases, the Citrus Unit 2 and the Hamilton Project, are contingent upon DEF placing units into service in time for inclusion in the first billing cycle of January 2019. DEF has combined several rate increases into one tariff sheet filing to smooth the rate impact to customers and to avoid the potential confusion of competing/multiple tariff sheets.

Q. What happens if either the Citrus Unit 2 or the Hamilton Project is delayed such that they cannot be placed into rates with the January 2019 bills?

A. DEF would remove the portion of the tariff sheet change that is related to the charges for that particular unit, if it were not placed in service in time for inclusion on January 2019 bills, and request Commission Staff administrative approval for the tariff sheets. DEF would then notify Commission Staff when the unit(s) is placed in service and request administrative approval of the new tariff sheets at that later point, to become effective with the first billing cycle the month after the unit is placed into service.

Q. How will the Commission Staff be able to confirm the accuracy of the tariff sheet changes, if the in-service date for either the Citrus Unit 2 or the Hamilton Project is delayed?

A. I have presented detailed information in my Exhibit No. __ (MO-2), specifically pages 4-8, to present the various scenarios in the event that both or either of the two units is delayed. Column (C) on pages 4-8 shows the tariff rates that will be in effect in November after the Citrus Unit 1 base rate increase, just before including any increases in 2019. Column (E) presents the tariff rate if only the Citrus Units 1 and 2 rates were added. Column (I) shows the rates if all three rate increases are effective (i.e. both Citrus units, the Hamilton Project, and the multi-year increase). The legislative and clean tariff sheets that I have included as my Exhibit Nos. __ (MO-3) and __ (MO-4) include the rate information found in Column (I). Columns (J) through (L) on pages 4-8 of my Exhibit No. __ (MO-2) present the rates under various scenarios in which Citrus Unit 2 and/or the Hamilton Project are not included in the January 2019 base rate increase. Using this information, Commission Staff should be able to respond to any changes, if necessary, to the tariff sheets if DEF is unable to bring the Citrus Unit 2 and/or the Hamilton Project on-line in time for inclusion on January 2019 bills. Collectively, by combining the rate increases into one tariff sheet filing, DEF expects to promote efficiency, avoid the confusion of multiple tariff sheets, and encourage a smooth rate impact to customers.

Q. **How did DEF calculate the multi-year rate increase?**

A. DEF calculated the multi-year rate increase consistent with the 2017 Settlement. Paragraph 12.b. of the 2017 Settlement states: “Effective with the first billing cycle for January 2019, DEF will be allowed a multi-year increase to its base rates as reflected in the chart below…” The chart, for 2019, permits an increase of $50

million using one method of uniform percentage increase, and an increase of $17 million using a second uniform percentage increase method. Method (1) provides: "Amount to be recovered through a uniform percent increase to the customer, demand, and energy base rate charges for all retail customer classes, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted." Method (2) provides: "Amount to be recovered through a uniform percent increase to customer charges for all retail rate classes except the interruptible and curtailable rate classes." Consistent with Paragraph 12.c. and Exhibit 6 of the 2017 Settlement, DEF has adjusted these amounts to reflect the new lower federal income tax rate resulting from the 2017 Tax Cuts and Jobs Act. My Exhibit No. __ (MO-2), page 1 of 8, provides the calculation details for the $41.1 million base rate increase (using Method 1) and page 2 of 8 provides the details for the $14.0 million base rate increase (using Method 2).

Q. What are the revenue requirements for the Hamilton Project?

A. As I discussed in my July 31, 2018 Direct Testimony, the annualized revenue requirements of the Hamilton Project is $15.2 million.

Q. **How did DEF calculate the percentage increase on customer bills associated with the Hamilton Project revenue requirements?**

A. DEF calculated the base rate adjustment associated with the Hamilton Project revenue requirements consistent with Paragraph 15.e. of the 2017 Settlement, which states, "Each base rate adjustment allowed by or implemented pursuant to this Paragraph is

to be reflected on DEF's customer bills by increasing customer demand and energy base rate charges by an equal percentage contemporaneously; however, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. The calculations of the percentage change in rates will be based on the ratio of (i) the forecasted jurisdictional Annualized Base Revenue Requirement for the solar project(s) covered by any single base rate increase to (ii) the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. The forecasted retail base revenues from the sales of electricity during the first twelve months of operation will be based upon DEF's billing determinants for the first 12 months following such project's commercial in-service date, where such sales forecast is that used in DEF's then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each such solar project's operation. DEF shall be authorized to begin applying the base rate charges for each adjustment authorized by this Paragraph to meter readings beginning with the first billing cycle on or after the commercial in-service date of that solar generation project."

Q. Has DEF calculated the solar base rate adjustment factor consistent with the 2017 Settlement?

A. Yes. As shown in my Exhibit No. __ (MO-2), page 3 of 8, DEF has calculated the solar base rate customer, demand, and energy factors for each rate class, consistent

with the 2017 Settlement. DEF utilized the same sales forecast as that utilized in DEF's August 24, 2018 projection filing in the CCR Clause.

Q. What is the estimated residential base rate impact of the Hamilton Project?

A. The estimated residential base rate impact is approximately $0.46 on a 1,000 kWh bill.

Q. **Have you provided tariff sheets to demonstrate the impact of the Hamilton Project and the multi-year base rate increase?**

A. Yes, my Exhibits No. __ (MO-3) and __ (MO-4) include the clean and legislative/redline versions of the tariff sheets impacted by the Hamilton Project and the multi-year base rate increase, as well as the Citrus Unit 2 base rate increase approved in Docket No. 20180084-EI.

Q. Does that conclude your testimony?

A. Yes.

MS. TRIPLETT: Thank you.

And then we would ask for the exhibits that have been marked 7 through 10 on the comprehen- -- comprehensive exhibit list to be entered into the record.

CHAIRMAN GRAHAM: If there's no objections to the exhibits, we'll enter Exhibits 7 through 10 into the record.

(Whereupon, Exhibit Nos. 7 through 10 were admitted into the record.)

MS. TRIPLETT: Okay. Thank you, sir.

And then, we would call Ben Borsch.

Whereupon,

BENJAMIN M.H. BORSCH

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. TRIPLETT:

Q And Mr. Borsch, you have been sworn in?

A Yes, I have.

Q Would you introduce yourself to the Commission and provide your address.

A Yes, my name is Benjamin Borsch. I am the director of integrative resource planning and analytics.

I -- my work address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q Thank you.

And did you file prefiled direct testimony and exhibits in this proceeding?

A Yes, I did.

Q Do you have any changes to those documents?

A No -- no, I do not.

Q And if I asked you the same questions today as are contained in your prefiled testimony, would you give the same answers today?

A Yes.

MS. TRIPLETT: Mr. Chairman, we request that the prefiled testimony of Benjamin Borsch be entered into the record as though read.

CHAIRMAN GRAHAM: We will enter Mr. Borsch's prefiled direct testimony into the record as though read.

(Whereupon, Witness Borsch's prefiled direct testimony was inserted into the record as though read.)

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE FIRST SOLAR BASE RATE ADJUSTMENT

FPSC DOCKET NO. _____

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

JULY 31, 2018

Q. Please state your name and business address.

A. My name is Benjamin M. H. Borsch. My business address is Duke Energy Florida, LLC, 299 1st Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as the Director, IRP & Analytics.

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

A. I am responsible for resource planning for DEF. I am responsible for directing the resource planning process in an integrated approach in order to find the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. I oversee the completion of the Company's Ten-Year Site Plan ("TYSP") filed each April.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009, I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy Corporation, I accepted my current position. Prior to joining Progress Energy, I was employed for more than five years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas-fired power plant projects in nine states. I was also employed for more than eight years as an environmental consultant with projects including development, permitting, and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

Q.

A. **Please give an overview of the Company's presentation in this filing.**

The Company is presenting testimony from three witnesses. My testimony will focus on the Company's demonstration of cost effectiveness for the proposed projects and their compliance with the terms set forth in DEF's 2017 Second Revised and Restated Settlement (the "2017 Settlement"). Two other witnesses will be presenting testimony. The testimony of Mr. Matthew G. Stout focuses on the characteristics of the solar projects presented for approval in this filing. It also provides details as to the Company's competitive solicitation processes, as well as the costs for the solar

projects. The testimony of Ms. Marcia Olivier presents the revenue requirements for the solar projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of the economic analysis which shows that DEF's proposed two solar projects presented in this filing are cost effective and consistent with the terms of the 2017 Settlement. My testimony covers several areas. First, I discuss details of the two specific solar projects covered by this filing. Second, I discuss the major assumptions and methodology used to perform the economic analysis. Third, I present the results of the economic analysis, demonstrating that the addition of the proposed solar projects is cost effective and consistent with the terms of the 2017 Settlement.

Q. Are you presenting exhibits in this proceeding?

A. Yes. They consist of the following exhibits which are attached to my testimony:

Exhibit No. __ (BMHB-1), "Solar Power Plant Assumptions;"

Exhibit No. __ (BMHB-2), "Load Forecast;"

Exhibit No. __ (BMHB-3), "Fuel Forecasts;" and

Exhibit No. __ (BMHB-4), "Cost Effectiveness (CPVRR) Analysis Results."

These exhibits are true and accurate.

Q. Please summarize your testimony.

A. In the 2017 Settlement, DEF is authorized to request cost recovery up to 700 MW of solar generation over the course of the 2017 Settlement period including one year following the expiration of the Term of the 2017 Settlement subject to the demonstration of cost effectiveness and other provisions. In this filing, DEF is proposing the construction and operation of 149.8 MW_{ac} of solar PV generation, consisting of two separate projects of 74.9 MW_{ac} each with in-service dates of late 2018 and early 2020, respectively. DEF performed an economic analysis and determined that these projects result in a reduction in the Cumulative Present Value Revenue Requirements ("CPVRR") to DEF customers for a total savings of approximately $130 million.

Q. Please describe the solar projects DEF is presenting for approval.

A. In this filing, DEF proposes two solar facilities. The first is a 74.9 MW facility in Hamilton County, called the Hamilton Solar Power Plant ("Hamilton Project") which will come into service in late 2018. Next is a 74.9 MW facility located in Columbia County which will be called the Columbia Solar Power Plant ("Columbia Project") and which will come into service in early 2020. Each project will generate approximately 195,000 MWhs per year. Key data regarding these projects are provided in Exhibit No. __ (BMHB-1). The projects are described in greater detail in Mr. Stout's testimony.

Q. What will these proposed solar projects cost?

A. DEF anticipates that the Hamilton Project will cost approximately $113.1 million to construct while the Columbia Project will cost approximately $109.5 million. These costs translate to a per kW cost of $1,511/kW$_{ac}$ for Hamilton and $1,461/kW$_{ac}$ for Columbia. This results in an average per kW cost of $1,486/kW$_{ac}$. The costs are described in more detail in Mr. Stout's testimony.

Q. What does the 2017 Settlement require DEF to demonstrate to obtain cost recovery for the solar projects?

A. DEF must demonstrate that the projected solar projects in each filing meet several required elements. The first demonstrates that the costs are reasonable and beneath a threshold cost of $1,650/kW$_{ac}$ for the weighted average construction cost of the projects in an individual filing. These elements are met, as described in Mr. Stout's testimony. DEF must also calculate the annual revenue requirements, as explained in Ms. Olivier's testimony. Finally, the solar projects must be limited to certain total MW size through one year following the Term of the 2017 Settlement, be cost effective on DEF's system, and DEF must demonstrate a need for the solar projects. The remainder of my testimony will focus on these last three requirements.

Q. Do the proposed solar projects meet the MW limitations set forth in the 2017 Settlement?

A. Yes. Paragraph 15(a) of the 2017 Settlement states that DEF may install up to 700 MW of solar generation over the term of the 2017 Settlement. Paragraph 15(d) provides cost recovery limitations on those projects such that the installations can be

spread across the term in a particular manner, at a rate of up to 175 MW per year except that unused portions of the total may carryover from year to year. Thus, up to a cumulative total of 175 MW may come online by the end of 2018, a cumulative total of up to 350 MW may come online by the end of 2019, a cumulative total of up to 525 MW may come online by the end of 2020, and the full 700 MW of solar projects may come online by the end of 2021 or within one year following the Term of the 2017 Settlement. The solar projects proposed here contribute 74.9 MW in 2018 and an additional 74.9 MW in 2020, so DEF is within the limitations set forth in the 2017 Settlement.

Q. Why is DEF proposing projects in different years, and one in 2020 in this filing?

A. In accordance with the terms of the 2017 Settlement, DEF has considered solar projects available both through DEF greenfield project development and through the acquisition of projects proposed by other developers. In this filing, DEF is proposing two projects acquired from other developers with various stages of project development already underway. DEF was able to acquire projects with advanced positions in the transmission interconnection queue and which DEF believes have good community acceptance and a straightforward path to receiving the necessary permits. In the case of the Columbia Project, DEF accepted a later in-service date in order to secure solar panels to be used in the project that are exempt from the import tariff.

Q. Will DEF be proposing projects to come into service in 2019?

A. Yes. DEF expects that in a future filing, DEF will propose additional solar projects to come into service in 2019.

Q. Are the proposed solar projects cost effective?

A. Yes. As explained below, DEF analyzed the total system cost of the DEF system with the projects as compared to the total DEF system costs without the projects, and found that the solar projects as proposed reduce the total system cost and are thus cost effective for DEF's customers.

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

A. DEF calculated the cost effectiveness in the same manner that it performs cost effectiveness evaluations of numerous projects including the development of the Ten-Year Site Plan. DEF calculates the total system cost projected over the life of the solar projects for a scenario with the solar projects and compares it to the total system cost calculated for a scenario without the solar projects. Lower total system costs for the scenario with the solar projects represents savings to DEF's customers. As with our Ten-Year Site Plan, this analysis is performed using the Planning and Risk suite of modeling tools to evaluate the production cost results. Project specific capital costs come from the project development teams and revenue requirements are then developed. Finally, project specific solar performance projections are developed using the PVSyst model and provided to the production cost model. This data becomes inputs to derive the system costs for the two cases developed with and without the solar projects in service.

In addition to the reference case assuming the base case fuel price projection and a carbon emission cost beginning in 2025, DEF also performed sensitivities based on low and high fuel price projections. Results of these differential CPVRR analyses, the difference between with and without the solar projects are shown below and in Exhibit No. __ (BMBH-4). The fuel price forecasts are shown in Exhibit No. __ (BMHB-3) attached to this testimony.

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

A.

- Load Forecast – The analysis uses DEF's most recent official load forecast developed in the fall of 2017 and presented as the base case load forecast in the DEF 2018 Ten-Year Site Plan ("TYSP") filed with the commission in April 2018. This load forecast is attached as Exhibit No. __ (BMHB-2).
- Fuel Price Forecast – The reference case analyses use DEF's most recent published fuel price forecast also utilized in DEF's 2018 TYSP. The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is

determined primarily by pipeline tariff rates. For the low and high fuel price scenarios, DEF developed ranges of natural gas and coal prices around the reference forecast based on the range of prices seen in the Energy Information Administration's high price (Low Oil and Gas Resource and Technology Case) and low price (High Oil and Gas Resource and Technology Case) forecasts.

- CO_2 Emissions Price Forecast – The CO_2 allowance price projections used in this filing are also DEF's latest projections used in the development of the 2018 TYSP. DEF's price projections are a proxy for regulations consistent with a goal to reduce CO_2 emissions 40% by 2030.

Q. Are there differences between the load and resource plan presented here and that presented in the DEF 2018 Ten-Year Site Plan?

A. Yes. Some updates which have occurred in the period since the development of the Ten-Year Site Plan are captured in the modeling for this filing. Specifically, these include the termination of certain contracts to purchase power from qualifying facilities. As I discussed earlier, the fundamental assumptions including the load forecast, fuel, commodity, emissions and electricity price forecasts are all those used in the Ten-Year Site Plan.

Q. What are the results of DEF's cost effectiveness evaluation for these projects?

A. DEF has found that the projects are cost effective for its customers. The total system costs calculated over the project lives when including the projects in the DEF resource plan are lower when compared to the total system costs excluding the

projects. The net results of this analysis (system costs with the projects minus system costs without the projects) are summarized in the table below and in Exhibit No. __ (BMHB-4).

CPVRR Net Cost / (Savings) of Proposed Solar Projects
$ Millions (2018)

Low Fuel Sensitivity	Base Case Fuel	High Fuel Sensitivity
(98)	(130)	(205)

Q. What benefits do the proposed solar facilities bring to DEF's system and customers?

A. The primary purpose of the proposed DEF solar projects is to provide customers with cost-effective, clean, renewable energy. These large scale solar projects and additional future projects to be filed under the 2017 Settlement will diversify DEF's fuel mix with dependable energy, and provide firm summer capacity, helping to meet DEF's needs for future capacity and satisfy DEF's need for future generation capacity.

Q. Given all these benefits, does DEF have a need for these solar projects?

A. Yes. DEF has a need for cost-effective clean generation that will diversify its fuel mix, and defer the need for future gas-fired generation.

Q. Should the Commission approve DEF's request for approval of this first group of solar projects?

A. Yes. As demonstrated above, these solar projects are cost effective and will provide DEF's customers with additional 149.8 MW of clean, reliable, renewable energy to meet its needs.

Q. Does that conclude your testimony?

A. Yes.

MS. TRIPLETT: And we waive the summary and tender Mr. Borsch for cross.

CHAIRMAN GRAHAM: Mr. Borsch, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Mr. Rehwinkel, the witness is yours.

MR. REHWINKEL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. REHWINKEL:

Q Good afternoon, Mr. Borsch. Good to --

A Good afternoon.

Q -- see you.

Do you have any of the exhibits that we've passed out earlier today?

A No, I do not.

Q So, Mr. -- Mr. Stout stole them.

A Yes, apparently he did.

Q I say that, tongue-in-cheek, not -- I'm going to give you 26 through 28. I have a copy --

CHAIRMAN GRAHAM: She's got it.

(Discussion off the record.)

BY MR. REHWINKEL:

Q And I think somebody has given you the others.

A Okay. Thank you.

Q Okay. I want to start off by asking you to

turn to -- if you could -- do you have Exhibit 21 or do you have your own copy of the --

A I --

Q -- RRSSA?

A -- do have my own copy, but I also have the exhibit provided here.

Q Okay. So, what I'd like for you to do is take Exhibit 21 --

A Uh-huh.

Q -- and turn to Paragraph 15C, which is --

A Uh-huh.

Q -- Page 27 of the -- of the document. And -- and ask you, is -- is this generally the -- the section of the set- -- 2017 settlement agreement that your testimony addresses?

A Generally, yes.

Q Okay. So, would it be fair to say that the -- the -- the large -- largest part of your testimony deals with what's Romanette No. 2, where it says: The issues for determination are limited to the reasonableness and cost-effectiveness of the solar-generation projects; i.e., will the projects lower their projected system Cumulative Present Value Revenue Requirement, CPVRR, as compared to such CPVRR without the solar projects.

A I would say that Mr. Stout's testimony related

to the question of reasonableness, but everything that comes after that, beginning with cost-effectiveness, is part of my testimony.

Q Okay. We heard some testimony about lease payments.

A Yes.

Q Is it your understanding that there -- other than a relatively-small piece of lease payments that are embedded in the construction and development costs that were capitalized, there are no lease payments in the -- the capital cost component that's presented for comparison purposes to the 1,650-per-kWac threshold; is that -- is that your understanding?

A That's correct.

Q Okay. Can you explain to the Commission, and for the record, how those lease payments are factored in, if at all, the analysis that you did?

A Yes. So, when we look at the CPVRR calculation with and without, we're looking at a life-of-the-project calculation. So, the calculation runs out -- I mean, we actually ran the calculations through 2050. So, all of the costs that we anticipate -- costs and savings, which we anticipate to be occurring over that period, are taken into account in the CPVRR calculations.

So, in the case of the costs on the project side, that includes the lease payments, property taxes, insurance, future FOM -- that is to say fixed operating-and-maintenance costs, which we -- we anticipate being incurred by the project.

And those are, in turn, offset by savings in energy and operating costs attributed to the system, which might otherwise be displaced had we not built the solar projects.

Q So -- so, in that answer, you're saying that the -- the stream of payments for the lease of these two properties is included in that overall revenue-requirement --

A Yes.

Q -- calculation.

A Right. I mean -- yes.

Q We also had some testimony about transmission costs.

A Uh-huh.

Q I think Mr. Stout testified that there's approximately $10 million for each project of transmission costs.

For the Hamilton project, he attributed some of these costs to overall system transmission-network benefit because of a ring bus that was installed. Are

you familiar with that?

A Yes.

Q Okay. Can you explain to me how, if at all, those costs would be included in the CPVRR analysis you did?

A Yeah, those costs are similarly included in the CPVRR analysis. In other words, the revenue requirements attributed to the recovery of the capital for those transmission installations are included in that life-of-project stream of payments that we were talking about a moment ago.

Q Okay. Now, if we step back to the lease payment, stream of payment, those costs would be included, if I could -- if -- if you know, in the revenue requirement attributable to the SoBRA and the base-rate component, itself; is that your understanding?

A Yes. My understanding is that those costs, you know, similar to the first-year O & M costs -- I mean, the -- it's all bundled together, the lease payment, the insurance, the property taxes, the first-year O & M are calculated together as part of the revenue requirement that Ms. Olivier uses to calculate the rate adjustment.

Q Okay. So, for the Hamilton project, assuming it went -- that -- that the -- that it went into service

in December of '18, sometime in January or February of this year, rates went up for Duke customers to pay for that project; is that right?

A That's my understanding. I don't know the specific month.

Q Okay. Sometime, we can say, in the first quarter.

A That is my understanding, yes.

Q Okay. So, customers are paying the 15 -- is that the 1,511 -- the 1,511 plus that O & M rev- -- revenue requirement -- those two components generally would be the revenue requirement that's built into their base-rate increase; is that your understanding?

A Yes, the revenue requirement associated with the capital investment plus the O & M and the lease payments that we were just talking about.

Q Okay. For the transmission piece --

A Uh-huh.

Q -- that we talked about, and Hamilton had a $10-million cost.

Is there any part of that revenue requirement that's in your CPVRR analysis that's baked into the rate increase that customers got in the first quarter for Hamilton project?

A No. That transmission cost or that

transmission investment is part of our general transmission investment in the system as a whole, which will be addressed in the next base-rate proceeding.

Q And same answer for a project that hasn't gone into service yet, Columbia. Again, for the specific dollars associated with that project, when it goes into service, the 1,461 plus the O & M costs that includes lease payments, taxes, and -- there was another piece there.

A All that stuff, insurance, maintenance --

Q Insurance.

A Yes.

Q That -- that will all go into a base-rate-increase component that will be part of a rate adjustment in the future.

A That's correct. That will go into service in -- into rates, essentially, in the first billing month following the in-service date of the Columbia project, which is anticipated to be March of 2020.

Q Okay. And likewise, the transmission-network upgrade that was described -- it's about $10 million, that -- the revenue requirement for that is not -- will -- and will not be included in the Columbia base-rate adjustment that -- that you expect to im- -- implement in 2020; is that right?

A That's correct.

Q Okay. Let me ask you if you can turn to Exhibit 26, 27, and 28.

A These are the confidential exhibits?

Q Yes, sir.

A Uh-huh.

Q And I -- I would probably echo your Counsel and admonish you not to verbalize any of the numbers --

A Yes.

Q -- in these documents.

Were you responsible, in part, for the preparation of the response to POD6 and POD7?

A Yes.

Q So, can you tell me, what was your role?

A Well, I worked with a member of my team and a member of Matt -- Mr. Stout's team to ensure that we agreed that we had correctly made the calculations involved. I provided quality assurance and oversight.

Q Okay. So, can you tell me if -- if you would, just turn, for example, to the Columbia document, which is Exhibit 27. And can you tell me, if you know, under the lease column, on the second line, where it says revenue requirement, NPV, thousands of dollars -- first of all, is that a confidential number, by itself?

A It's my understanding that it is, yes.

Q Okay. Can you tell me what that number represents with respect to any revenue requirement that you use in your CPVRR analysis?

A Yeah, that number represents the equivalent net present value of the -- I mean, it's essentially the CPVRR just for that single stream of the lease payments.

Q Okay. So, this is only lease payments. Nothing -- not the -- if we're Columbia, not the 1,461 or the taxes or the maintenance or the insurance.

A That's correct.

Q Okay. So, if I turn to 28, which is the Hamilton project, the -- the corresponding equivalent number, under the lease column in the second line that's shown there, is -- would also be the same. It's just a stream of -- of payments that's related to the -- the lease payments.

A That's correct.

Q Okay. Are you familiar with the capacity factor that's associated with the -- with the -- the two projects, Hamilton and Columbia?

A Yes.

Q Does the capacity factor that -- I think Mr. Stout said one was 29 and the other was 30 --

A Uh-huh.

Q -- percent?

A Right.

Q Does that -- how does that factor into your CPVRR analysis?

A Well, the capacity factors are actually a reflection of an annualized average of the behavior of the units. So, when we do our analysis, we actually break those down to a projected hourly performance shape for the projects, which is based on a projection of, you know, both -- several years of average irradiance and the technical specifications of the projects, themselves.

So, using that, we have an -- we get an hourly projection of what the performance of the units will be -- in other words, what percentage of the nameplate solar will appear in each hour. And that energy production and, you know, capacity production in that hour is used in our production-cost model, and it essentially offsets.

So, if you imagine that we do -- when we do -- we run a base case, which has no solar in it. We run a second case, which includes these projects. And so, because we have this production shape for the projects, themselves, the required amount of conventional generation is, then, reduced to offset that, so that -- that overall shape.

So, the higher the capacity factor that we have -- it represents, you know, more hours or more energy across the whole year. It's not strictly a measure of hours because, of course, you know, you might have an hour in which it was at 50 percent or 70 percent, but across the whole year, the amount of energy which is produced -- a higher capacity represents more -- or a higher capacity factor, rather, represents more energy, which, in turn, offsets a higher amount of energy that you're getting from other sources.

Q Are you -- and I know it's not an exhibit you sponsored, but are you generally familiar with Mr. Stout's MGS-5, his comparison of these two projects, Columbia and Hamilton, with the -- the publicly-discernible projects, if you will, of TECO and FPL?

A Yes, I mean, I -- at a high level, I'm -- I'm familiar with this.

Q Okay. Is there anything that you know about the projects and the -- the way they are configured and designed for implementation by Duke that offsets or ameliorates any of the cost differential that these projects show relative to those other companies' projects, if you know?

A Well -- so, I'll start with this: I don't know the details of their projects. I do know that when

we looked at various designs for the Duke projects, we selected designs which produced the highest energy value for the projects relative to the capital costs.

So, you know, the projects that we were designed and the DC-AC ratios and the single-access tracking choices produced the most benefit for those projects based on our load shape and -- you know, on the responses of the individual projects.

I can't directly compare them to the other companies' projects, but I can say that, when we looked at alternate designs, these were the designs which produced the most benefit.

MR. REHWINKEL: Okay. Mr. Chairman, those are all the questions I have.

Thank you, Mr. Borsch.

CHAIRMAN GRAHAM: Okay. Mr. Brew.

MR. BREW: Thank you, Mr. Chairman.

EXAMINATION

BY MR. BREW:

Q Good afternoon, Mr. Borsch.

A Good afternoon.

Q I guess, why don't we start -- on Page 3, you list your four exhibits, the solar-plan assumptions, load forecasts, fuel costs, and then your CPVRR analysis. Why don't we just go in that order.

A Okay.

Q On your Exhibit 1 --

A Yes.

Q -- the -- just to confirm the numbers, the -- the nameplate rating, the 74.9 megawatts for each, and the projected capacity factor, you got from Mr. Stout?

A Yes.

Q Okay.

A Well, from people on his team, yes.

Q Okay. And the -- the capital cost is also, as per the exhibit, Mr. Stout's exhibits?

A Yes.

Q Okay. The capital cost per kWac -- the capital cost dollars in millions -- do you see that?

A Yes.

Q Do those numbers on that -- in that block include the $20 million of other network upgrades?

A No, they do not.

Q Okay. And so, those costs are not picked up in Mr. Stout's estimate, not included here, and not included in the request for rates here?

A That is correct.

Q Okay. The -- well, they'll all go in succession, I imagine.

The 74.9 megawatts nameplate-capacity

rating -- that's for the first year, right?

A Yes.

Q And then there's a steady degradation of the panels from there on out?

A Yes.

Q And that would affect the nameplate rating, the projected capacity factor, the assumed energy production.

A Yes; although, they vary a little bit differently because, recognizing that the DC-to-AC ratio -- so, the panels degrade on a DC basis. Because of the way the projects are designed, there are some hours in which the DC output exceeds the AC output. So, during those hours, there would actually not be a degradation during those hours. So, it -- it's not exactly a linear decline in energy, but it -- in general, yes.

Q Okay. And so -- and your table, assuming the production and capacity factors, assumes a steady degradation of the panels over the 25-year --

A Yes. The --

Q -- lease life.

A Yes.

Q Okay. And the capital cost per kWac is based on the first-year numbers.

A Correct.

Q Next, your -- just -- just to confirm your -- Exhibit No. 2 shows the load forecast in terms of summer and winter firm demand and net energy for load. Those numbers are derived from your last ten-year site plan?

A Yes, from the one filed in April of 2018.

Q Okay. Not the one that's probably in the mail today.

A Not the one that -- yeah, that appeared yesterday.

Q Yeah. The one from last year, or the forecast run through 2027 -- can you explain how you derived the subsequent years?

A Well, shall we say that our reporting requirement to the State is that we provide a ten-year projection of our load forecast, and all the other details that are included in the ten-year site plan, we do -- actually do a longer projection.

And this fore- -- the -- the methodology that's used for the longer projection is essentially identical to that outlined in the ten-year site plan and this -- these numbers reflect that longer projection.

Q Okay. So, that -- that it's -- for the first ten years, it matches up with your base case --

A Yes.

Q -- for the summer and winter firm peak?

A Correct.

Q And for 2028 and beyond, it's based upon a company forecast that's not shown in the ten-year site plan.

A That's correct.

Q And just to confirm, currently the -- the company is actually winter-peaking, but you expect it to either cross over or be roughly equal, roughly the same, going forward?

A Yeah -- yes. We expect that there's going to be kind of a -- and the trends have tended towards the levelization of the summer and winter peaking. There are a lot of factors that are moving that back and forth between the two that include expectations of future wholesale contracts, expectations of energy-efficiency programs, and other factors, but in rough terms, we're expecting them to be very close to each other for a long time.

Q Okay. And so, when I turn to the solar, you're assuming zero values in meeting winter peak, right?

A That is correct.

Q Effectively an energy resource.

A Effectively none, yes.

Q Okay. And for -- for meeting summer-capacity requirements, you are -- you have a -- you have a nameplate rating, the 74.9 megawatts. You have a capacity factor overall of about 30 percent.

A Uh-huh.

Q But you're assuming a -- a summer capability value of a -- what -- 42.7-percent -- megawatts for each?

A Right. It's 57 percent of the nameplate.

Q Okay. And your plan is to apply that ratio going forward until you learn better, from experience?

A Until we have better information, yes.

Q Okay. Now, would any other assets be -- receive a capacity payment from Duke with those performance characteristics? If you're a qualifying facility, for example, would you qualify for capacity payments?

A We have, I think, in other filings, set forth the sense that we are open to negotiating with third parties on the basis of their receiving a capacity payment, but subject to conditions having to do with their reliability and commitment, I guess, for lack of a better term, to actually provide that energy on the peak.

That's a little bit beyond my area, but I will

say that, you know, I know that we have worked very hard to establish criteria which will set forth the idea that those parties will have the same obligation to appear at the peak that we hold ourselves to.

Q Okay. So, right now, from your -- that last ten-year site plan, you have listed about 511 megawatts of co-generation and firm renewable capacity.

A Yes.

Q And you're assuming that's all going to go away?

A Most of the those contracts, and in the 20- -- I mean, they're all under contract. So, those are all contracts which were contracted before 2000. They end mostly in the 2022, '23, '24 time frame.

We have assumed, for the time being, that those contracts are not likely to be renewed, although we will negotiate with each of those counter-parties about a renewal.

I mean, one thing that -- to -- to bear in mind is that the contract structure of those contracts, which was negotiated back in the nineties, has caused the capacity and energy payments that we're paying to those counter-parties to be significantly out of the market relative to today's energy.

So, while we will negotiate with them, we will

negotiate with them based on our current avoided cost or then-current avoided cost, in the late twenties.

Q Now, I did want to talk to you about what your plan is for negotiating with those units, only that, for the purposes of your analysis here --

A Uh-huh.

Q -- you eliminate that 511 megawatts as capacity in your system. So, when you're looking at reserve margins, by 2025, those are all gone. They don't count ma- -- as capacity?

A Yes, that's correct. It's our estimation -- we have to make some assumption about what will happen with those contracts. And we've assumed that they will end.

Q They will end -- either the -- the generators will stop generating or they'll only get paid as available energy.

A Or they'll contract with somebody else or, you know, any other possibility, yes.

Q Okay. But for -- for our purposes here, in terms of the -- the benefits in your cost-effectiveness analysis, you're assuming fuel-cost benefits. You're assuming carbon-emission benefits beginning in 2025, right?

A Correct.

Q Okay. And are you showing any capacity benefits?

A Yes. As, I think, outlined in my testimony -- and there's an interrogatory response -- we created a resource plan for with and without the solar. And we compared the capacity -- future capacity costs of each of those plans to each other, and ascribed the savings in capacity costs due to deferral of future conventional generation to the solar projects.

Q And to be clear, through 2030, the only changes in your resource mix is you defer 226 megawatts of CTs in 2026 to 2030; is that right?

A I would have to look at the exhibit, but that sounds correct.

Q Okay. And there's no other changes in your resource mix other than the fact that you drop 511 megawatts of co-generation from the mix.

A Well, no, that's not true because, you know, there are a variety of assumptions. I mean, as in our ten-year site plan, there are a variety of assumptions baked in with regard to other contracts and -- and other projects that are already committed; you know, as, for instance, the addition of the firm capacity of the Osprey combined cycle when we get the transmission finished and, you know, changes in some of our other

contracts with non-co-gen sources.

So, there's a whole array of assumptions about what our future generation will be.

Q But the Osprey was already in your ten-year site plan to go from 250 megawatts up when you did the transmission upgrade, right?

A Right. I mean, all these assumptions --

Q I'm talking about the changes.

A Yeah -- no, all these assumptions are the -- except for the -- except for the deferral of the peaker that you referred to a moment ago, all the rest of these assumptions are the same as they are in the ten-year site plan. The -- the termination of the co-gen contracts that you're referring to is in the ten-year site plan.

Q Okay. All right. So, when we get to the solar, you're looking at any new convention, whereas, instead of demonstrating capacity value, you're forecasting it, right?

A Well, we are always forecasting capacity value, you know, in the sense that we forecast what a conventional generating unit might have for capacity value in the future. But I mean, it is a little different with the solar. I don't disagree with that.

Q Okay. Then let's try it differently. In your

ten-year site plan, you've always talked about dependable generating capacity.

A Yes.

Q Dependable resources.

A Correct.

Q Based on measured metrics?

A Yes.

Q So, a co-gen that's making steam has to demonstrate that they can generate steam and produce the power that they promised, right?

A Correct.

Q That doesn't apply to renewables, right? You're forecasting -- or to -- the question is: For the solar, you're forecasting how much energy you expect to be available at the time you need it.

A That's correct. And as I -- there is also an interrogatory response -- I believe it's to staff's third -- in which I explain the methodology behind the way that we came up with that number and also the fact that we try to take a reasonably-conservative approach to determining that number.

There's actually -- I mean, we -- depending a little bit on how many hours you count or how you look at the approach, you could have come up with a higher number.

Q But this would be -- solar would be the only resource on -- in your mix that gets a capacity value in that fashion, right?

A It is a different kind of a resource, yes.

MR. BREW: Okay. That's all I have. Thank you.

CHAIRMAN GRAHAM: Thank you, Mr. Brew.

Mr. Moyle?

MR. MOYLE: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MOYLE:

Q Good afternoon.

A Good afternoon.

Q Mr. Brew asked you a host of questions about the ten-year site plan that you referenced in your testimony. And I guess you filed your ten-year site plan yesterday; is that right?

A We did.

Q And is there any material change in the ten-year site plan you filed yesterday as compared to the testimony that you've given today?

A I'm not sure how we would define "material change." If, by that, you mean when is the first unit in the plan, the answer is no. There are some differences in our projected expectations around the

load and the fuel forecast and, you know, mostly in areas of -- of some of our wholesale contracts.

I mean, you know, as -- as in any change from one year to the next, in the ten-year site plan, there are a -- a host of moving parts, but you know, no large new generating unit appeared this year compared to last year and no large generating units that were in last year's disappeared.

Q Do you have all the cogeneration contracts still going away, as you did in response to the questions from Mr. Brew about the last year's ten-year site plan?

A Yes.

Q All right. And so, from your appearing here before the Commission today, under oath, you're -- you're comfortable with your testimony as provided vis-a-vis the 2018 ten-year site plan or the 2019 ten-year site plan?

A There are always going to be variations, but I would say, generally speaking, the -- since that -- we have benefits for building the solar projects, under either base case, is still true.

Q Okay. In response to a previous question, you identified Duke's load shape and how that was important with respect to determining peak load.

What -- what is Duke's load shape?

A I'm not exactly sure how to answer that question. I mean, we have a projection of the hourly load, you know, across the year. That projection includes -- I mean, it's, you know, put together from a number of factors, which includes our ex- -- you know, principally, our expectation of what different classes of customers will use hourly and, you know, what we have committed to our wholesale contracts.

So, it gives -- yields an -- a shape for every hour of -- of what we expect the load to be. There's a -- obviously, there's a significant weather component that becomes part of that. So, it's probably not easy to say, you know, what is the load shape. It goes, you know, up in the afternoon and down at night, but you know, it's different for each day of the year.

Q And did I understand you correctly, in response to a prior question to indicate that, with respect to winter peak or summer peak, it's -- it kind of flips between the two? Or maybe the better question is: Are you a winter peak or a summer peak, and if so, please explain.

A Yeah, I mean, it's probably fair to suggest that our expectation going forward, based on, you know, our 30-year weather projection, our expectations

throughout customer classes, energy efficiency, and the other factors that build the load forecast, is that our, you know, winter-peak-hour demand and our summer-peak-hour demand are going to be relatively close to each other for the forecast period.

Q What -- what is your projected percent growth annually, in terms of net energy for load? If you -- if you know.

A I don't have the exact figure off the top of my head, but it's a little more than 1 percent.

Q Okay. And I just want to understand, from a -- probably a high level, how -- how -- how you treat renewable energy in your planning processes. I mean, your -- your duties and responsibilities include preparing the ten-year site plan, right?

A They do.

Q And you're the person at Duke Energy Florida who's responsible for planning and making sure that you have sufficient assets to meet load, correct?

A Yes.

Q Okay. And -- and so, how -- how do you all account for renewable energy in the planning process? And is there a distinction between solar renew- -- renewable energy versus other types of renewable energy? It's -- it's a broad question.

A Yeah. Well, let me take the back end of that first. Every technology that we consider has its own, you know, qualities. So, when we look at a technology, we consider its dispatch-ability, its likelihood to be there, you know, whether it should -- whether it should have outage rates associated with it, fuel certainty, if there's a fuel associated.

So, each of the technologies that we consider, renewable or conventional, has, you know, its own production characteristics. So, that part of it is true for every section.

And now, I'm going to have to admit, you're going to have to give me the first half of the question again.

Q Well, let -- let me ask you this: Like -- so, for a biomass plant --

A Uh-huh.

Q -- that is under a contract -- I assume that, from a capacity factor, you would rate that much higher than solar; is that right?

A I mean, generally speaking, yes. I mean, we look at plants with an effort to understand -- especially, you know, most of those kinds of plants, biomass, for instance, are under contract to us. We don't own them.

So, you know, we make an effort to understand their fuel scheme and, you know, their ability to produce. And that's a combination of -- well, it's primarily driven by whatever the terms of the contract are.

If we have contracted and they have committed, under contract, to be able -- you know, at some capacity factor, under certain hours, we will, generally speaking, bake those commitments into our plan, unless we have some history under which they have not demonstrated the ability to meet those commitments.

Q And -- and -- and with that contractual relationship, com- -- compare and contrast that, if you would, to how you are handling the capacity from the two plants for us today, Columbia and Hamilton.

A Well, you know, first of all, these are owned facilities. So, as with all our owned facilities, we, you know, estimate what we think their performance is going to be in terms of their availability, their -- you know, an outage factor, if any.

Second of all, you know, in the case of the solar facilities, we are essentially estimating, you know, what is the reliability of the fuel stream, in this case, the solar power.

So, we have, you know, created a projection of

the solar irradiance, and we have tied that projection of the solar irradiance to the anticipated load and used those projections to create an understanding of what we believe the solar performance will be.

Q And -- and that would be the capacity factor that you testified to previously?

A Well, it informs both the capacity factor and the capacity at peak value, yes.

Q Okay. And you said that, with respect -- I think -- correct me if I'm wrong -- but for planning purposes, if, for example, there was a solar facility that was -- was rated -- it will be simpler math. So, rather than 74.5, let's just use a hundred.

If it was a hundred megawatts, you would assign 57 megawatts of that in the -- for the purposes of doing calculations related to your ten-year site plan for reserve-margin purposes; is that right?

A Yes.

Q And how did you come up with the 57 percent?

A Well, there's an extensive answer to this in the discovery, but the short answer to -- to that is that we took a projection on our load forecast of the peak hours of the summer, and we -- in our -- in our load -- in our, you know, performance projection, we have, you know, matching hours of load and solar

performance.

So, what we looked at were the 10 percent of the highest hours of load in the summer and the associated solar performance that went with those hours. And then, we sorted that 10 percent of the hours based on the solar performance and we took the lowest two-thirds of those hours and averaged them to get the 57 percent.

And we did that with a recognition that we were being deliberately somewhat conservative, you know, first of all, because the solar power is intermittent and, therefore, doesn't have the same degree of reliability as, you know, something that we can turn on and turn off; and second of all, because, you know, it's early days with solar on our system. And we believe that a degree of conservatism was appropriate.

And you know, as I have -- have said before, going forward, as we get more data, we will continue to re-look at that value.

Q Do you -- do you think that -- that the analysis and the calculations and the judgments you -- you made would be similarly applicable to other entities with solar assets in the State of Florida, with respect to the percent of nameplate rating that's used for reserve-margin purposes?

A Well, I mean, I can -- I mean, I think the other utilities have said what their values are in their various ten-year site plans and related SoBRA filings. I do not know how they reached those calculations.

Q Yeah, your -- yours is a little higher than others; is that fair?

A Ours is just -- just a touch higher, but that also may have to do with the fact that, you know, we're -- at least relative to Power & Light, we're using tracking, and they're using fixed-tilt facilities.

I'm not as familiar with how the Tampa Electric calculation is put together.

Q Okay. I want -- I want to ask you a few questions about one of your charts, but -- but you -- as part of your testimony, you -- on Page 8, I made a note, that you are looking at -- with respect to price forecasts, you provided price forecasting for the cost of coal; is that right? It's Line 16.

A Yes.

Q Okay.

A Coal, natural gas, oil.

Q And -- and I was thinking coal was a very small portion of your generation mix. Am I -- am I wrong in that?

A Well, it's an ever-dwindling portion of our --

of our mix at this point, yes.

Q What -- just -- just, for the record, what is it -- what is coal in terms of your generation mix?

A Well, I think that we -- I -- well, I could look at my -- I could look at my ten-year site plan and tell you for sure.

Q The '18 or '19?

A This is last year's.

Q Okay.

A I wanted to keep it consistent with the filing, so I haven't brought out this year's yet.

Q Okay.

A But you know -- so, one way to look at this is, in the ten-year site plan, we show that our actual for 2017 -- the percentage of energy driven from coal was 20 percent. We expected that to be maybe just a touch higher in 2018 and '19, and then declined into the teens, you know, in the years going forward.

Q Okay. And same question with respect to renewable?

A Well, the -- the renewables -- you know, we have a -- you know, again, in the forecast -- you know, to the point Mr. Brew was making earlier, we have contracts for those QF projects, which amount to a little bit more than 4 percent of our energy mix in 2016

and '17, and it maintains that level until later in the -- or well, into the early twenties, '23, '24, when those contracts start to run off and then we see that number decline, eventually, to zero.

Q So, you'll go to a zero-percent renewable?

A Right -- well, I shouldn't -- that shouldn't be said zero-percent renewables. It's zero percent for those contracts. Now, we do also have contracts with biomass -- or I should say, municipal solid-waste facilities, which we assume will be renewed. And we also have -- well, in this site plan, there was one ongoing biomass contract, which actually has since been ended, so -- but it showed in here, at the time, as being a little less than 2 percent of our energy.

And of course, we have a growing percentage of the energy, which is derived from solar over time, which rises up to the 8- or 9-percent level by the end of the period.

Q On Page 9, you say that, quote, DEF's price projections are a proxy for regulations consistent with a goal to reduce CO2 emissions 40 percent by 2030.

And I assume you're talking about assumptions that were made when you were running your -- your model; is that right?

A Yeah, our -- we have an assumption of what a

CO2 price might look like or, you know, recognizing that that may be interpreted as a price, there are a lot of different ways that that regulation could come into effect, but the price essentially acts as a proxy for a variety of different regulatory structures.

But yeah, we -- that's consistent between the ten-year site plan and this analysis.

Q Okay. And when you use the word "goal" here, who -- whose goal were you referencing? Is that a Duke goal or a -- you know, an EPA goal or what -- what -- what's the context of goal to reduce CO2 emissions 40 percent by 2030?

A Well, that is consistent with the Duke's sustainability targets, on an enterprise level, not necessarily at a Florida level, but it's -- you know, also consistent with some of the models that are consistent with, you know, international climate agreements, Kyoto, Paris, so on -- so, it -- it -- it's kind of a ballpark target that is consistent with other, different projections.

Q Okay. With respect to the reserve margins that you currently have in place that these solar projects are being added to, could you just provide information as to what the current reserve margins are before these projects are -- are added? I mean, you --

A I believe that's here in my testimony somewhere. Hmm. I know that table is actually in my responses here, but --

Q I didn't see it in your testimony, but --

A It's -- I think it's in the interrogatory responses. Give me just a second. Let's see if I can find it.

Q And I can ask you another question while you're looking --

A Okay.

Q -- if you want to multi-task.

A Sure. Why not.

Q Yeah. You currently plan to a 20 percent reserve margin; is that right?

A We plan to a minimum 20-percent reserve margin.

Q Would it be fair to say that the reserve margins that are in place now are above 20 percent and the solar is -- is --

A I'm --

Q You know, without the solar?

A In the near term, yes.

Q And that's the chart you're looking for?

A Yeah, that's the chart I was looking for, which I'm not finding, but --

MS. TRIPLETT: Mr. Chairman, I may have found it, if you --

CHAIRMAN GRAHAM: Sure.

MS. TRIPLETT: Mr. Borsch, I think, perhaps, staff's response to first set of interrogatories, No. 5.

THE WITNESS: Ah, yes. Okay. That's sounds right.

MS. TRIPLETT: There's attachments that are referenced.

THE WITNESS: Yep. Thank you.

Yeah. So, this table shows that we, you know, have a near term with or without the projects, frankly, close to -- and we'll start with this. You know, we've got two projects that are 57 percent of 74.9 megawatts. So, in aggregate, they add 80 megawatts to our roughly, you know, 10,000-megawatt system. So, they're not -- not exactly moving the needle here in terms of the reserve margin, itself.

But -- so, you know, having said that, you know, we have a situation in the near term where the capac- -- the reserve margin is in the upper 20-percent range. And then, over the period of the ten-year site plan, it dwindles back towards the

20-percent by about 2027 or 2028.

And you know, obviously, the solar, as I say, that moves projects around, but it doesn't have a significant impact on the overall reserve margin.

BY MR. MOYLE:

Q Right. And just for the record, the doc- -- could you indicate what you're referencing in response to that question?

A Yes. I am looking at my response to Staff Interrogatory No. 5.

Q Okay. And -- and for 2018, when this is coming in, what is the -- what is the reserve margin?

A We have 24 percent. And then, you know, it goes to 30 percent. These are summer-reserve margins, mind you. So, the bump from 2018 to 2019 reflects the addition of the Citrus combined cycle.

Q And that takes it to 30?

A Yeah.

Q Okay. All right. The -- just switching gears a little bit to another line of questioning and -- I think will be my last -- the -- the carbon costs that you had talked about -- I mean, you've used carbon costs in your -- in your analysis, right -- in your CPVRR analysis?

A We have.

Q Yeah, and -- and you decided as to a year when carbon costs would become a reality, correct?

A Yes.

Q And -- and what was that year and what was the basis for your decision as to why you thought carbon would become -- carbon taxes or prices would become a reality in that realm?

A Well, the year that we've used is 2025. And perhaps the way to say this is that we think 2025 is the earliest year in which it is reasonable to assume that there will be a carbon price. That would be dependent on, you know, the time it would take for an administration, which presumably would be the next administration, to promulgate a rule and, you know, implement said rule.

Q Okay. And are -- were you assuming federal or state or combination with respect to what --

A Our --

Q -- that administration would be?

A Our assumption is based on a federal program.

Q And was this an assumption that you made or did you have third-party outsiders help you with the -- with the judgments, with respect to future carbon pricing?

A No, this is a -- a -- a model of the potential

pricing, which Duke developed internally.

Q It's a proprietary Duke model?

A Well, I mean, we've told people what the price is. I mean, I -- I can tell you pretty much, you know, how it comes together.

Essentially what happens is that, you know, as I -- we mentioned earlier, we had assumed a target of -- of a 40-percent reduction by 2030. So, basically, we did some modeling across all the Duke jurisdictions of different price schemes. And we selected one which would essentially force the response of the systems to achieve approximately that target.

Q So -- so, it was being driven by the 40-percent reduction --

A Correct.

Q -- number.

A Yeah.

Q And --

A That's 40 percent from 2005, I might add.

Q Right. And -- and -- and just to make sure I'm clear on that, you said that was a combination of a Duke enterprise number and then some numbers that were considered as various international conferences?

A Right. I mean, that's where the -- yes. I'll just stop with yes.

Q The Paris Accords or the --

A Right.

Q The Kyoto Accords?

A Uh-huh.

Q All right. Let's -- let's flip to the -- Exhibit 4. And you -- this is a document that you did or your staff did?

A Yes.

Q All right. I am -- the numbers that are positive numbers -- what do they represent? They represent a cost?

A The positive numbers represent costs. The negative numbers represent savings. I mean, all of these numbers are differentials between the without-solar case and with-solar case.

So, in each case, the positive number represents a cost. It represents the -- the solar case being more expensive for that category, or a negative number represents a savings. It represents the idea that the solar cost is less expensive than the base case or the without-solar case.

Q Okay. And -- and -- and with respect to, for example, conventional generation, there's no -- there's no variability in there. And that's because your generation fleet is what it is and that number would be

the same throughout all three columns?

A Well, the reason that the conventional -- the conventional-generation-savings number that's there represents the deferral of future generation. So, that resource plan doesn't vary with the fuel prices.

Q And what --

A It's based on when we needed future generation for each one of those cases, as Mr. Brew was alluding to earlier.

Q Okay. And what was -- what was the conventional generation combined cycle, you're assuming?

A No -- well -- no. In -- I mean, there are combined cycles in the plan, but because of the relatively-small capacity of the solar projects, they don't defer a combined cycle. They defer peakers.

Q Okay. And the prior witness indicated you might be able to talk in broad terms about the cost of gas versus solar, and I had asked him a question, is -- is solar getting to a point where it's competitive with natural gas, in your judgment?

A Yeah, I -- no, I mean, that's what this analysis says is that we're getting there. We're -- we're very close, yes. I mean, it depends a little bit on how you measure. I mean, you know, there are very different resources, and you sort of have to look at --

I mean, on a life-of-project basis, you would say that the answer to that is yes, but if you look at it, you know, on a short-term basis, you know, where you're talking about what's going to happen in the immediate future, the revenue requirements of the solar versus the fuel costs of the gas -- I mean, it depends on how you set up the assumptions, but at a high level, I'll say the answer to that question is, yes, they're getting to be quite competitive.

Q Okay. All right. So -- so, I -- I just briefly -- the Hamilton 153 and the Columbia 131 -- where do those numbers come from?

A Those are the revenue -- the CPVRR equivalents of the capital cost prices that we were looking at in Exhibit 1.

Q Okay. And then the line where you have environmental costs without the carbon --

A Uh-huh.

Q You have a zero and a one and a one. What -- what are -- what are those values?

A Those represent savings in expectations of allowances for knocks and socks --

Q And -- are these -- are these dollars? I mean, I don't see anything on the -- on the chart --

A Oh --

Q -- that says the 98 and the 130 --

A That's a good point.

Q -- and 205 is dollars, but --

A Yeah -- no, these are millions of dollars expressed in CPVRR.

Q So, under your analysis, then, under every -- every case, every assumption, with respect to carbon and fuel, there -- there's no situation in which the solar projects are not better for consumers in -- in your judgment; is that right?

A That's correct. The projects prove to be cost-effective in CPVRR terms in all the cases that we examined.

Q Yeah. And did you -- when you ran this analysis, did you run it out for years? I mean, so -- you know, I've seen other -- other analyses where it shows, maybe -- maybe, in a certain year, the lines cross and you start saving money, but this is just kind of a cumulative analysis that you did that doesn't show the 30 -- you did it through 30 -- 31 years; is that right?

A Right -- well, as you can see on the table there, it says that we ran the analysis through 2050. So, yes, that's the cumulative, you know, impact of -- of the savings -- cost and savings through 2050.

Q Yeah. And why -- why did you -- why did you run it through 2050?

A Because both projects would have reached end of life by 2050.

Q And that's what you're depreciating them at, is 31 years?

A 30 years, but recognizing that Columbia doesn't come into effect until March of 2020, so...

MR. MOYLE: Okay. If I could just have one -- one moment.

CHAIRMAN GRAHAM: Sure.

BY MR. MOYLE:

Q Just a couple of further questions. In response to a prior question, you had said that you had considered alternative designs to the projects that are before the Commission today. What -- what were -- what did -- what were you referencing when you said you considered alternative designs or alternate designs?

A Well, we looked at both tracking and fixed-tilt. We looked at a range of DC-to-AC ratios. That was basically the number of alternatives.

Q Did -- did you consider any other types of renewable energy or it was just all alternative designs within the solar --

A No, this was --

Q -- scope?

A I mean, this analysis was, you know, strictly on, you know, what was the best alternative among the solar projects. I mean, as you know -- I mean, this particular effort was to participate in the opportunity laid out in the settlement to build the solar projects. And that's what we were focused on.

Q In -- in the conventional cost of conventional-generation number, the 165 that's on your Exhibit No. 4 --

A Uh-huh.

Q What -- what all is in that number? Is it totally deferral of -- of construction?

A It's deferral of construction, associated transmission, and associated firm gas commitments.

Q And those firm gas commitments are what you would need to run the equivalent amount of -- of fossil fuel, natural gas generation?

A Well, I mean, I guess the right way to say that is, you know, if we have, for instance, in the example that Mr. Brew cited earlier, the first unit that gets deferred is a 2026 peaker. And it defers from 2026 to 2030. And so, we have a capital cost associated with that project, we have a transmission cost associated with that project, and we have a firm gas commitment

cost associated with that project.

So, essentially, the savings relative to that particular unit are to move that unit, move those costs from a 2026 commitment to a 2030 commitment. And there's a savings associated, obviously, with that deferral. And then, post-2030, there are some other additional projects that get deferred. And I think there's actually one peaker that gets eliminated at the very end of the plan, so...

Q The -- there's a requirement in the settlement agreement -- I can put my hands on it if -- if you would like, but it requires that regular filings be made with the Commission with respect to how the solar units are performing and at what costs.

A Yes.

Q Are you familiar with that?

A Yes.

Q Yeah. Are -- are those filings being made for the project that's already completed and operational, if you know?

A It's my understanding we have made the first filing, yes.

Q Okay. And you plan to make the filing --

MR. REHWINKEL: (Indicating.)

THE WITNESS: Okay. Two? Okay.

Yes, I mean, those filings will be made on a monthly basis, going forward.

BY MR. MOYLE:

Q Okay. And -- and -- and oftentimes we -- we've been in a lot of cases over the years with CPVRR analysis and, you know, it's a proposition about monetary savings.

Do you all -- do you all actually ever track that to -- to see, hey, were we -- were we right, were we close, were we way off, with respect to these type of forecasts?

A I'll say, generally speaking, the answer to that question is no -- I mean, in part because a CPVRR analysis is done, you know, over a many-year period. You know, typically it's done on a life-of-a-project basis. So, you know, that's a 30- or 40-year basis. So, it's kind of difficult to look back and say, you know, did we achieve them -- and 30 years from now, you can ask me that question, but we, you know, haven't been looking back at the first five years, necessarily, of a 30-year analysis.

Q But -- but the analysis would have -- have segments, yearly segments. So, at year ten, you could say, okay, here is what we projected for ten years; how are we doing? I mean, is --

A Uh-huh.

Q Isn't that right?

A Well, we could do -- you recognize, of course, that we do our best to project the future and what's going to happen. And then, you know, reality happens and then, you know, the recession hits, the shale boom hits. You know, there are a whole lot of things that happen along the way. You know, we do our best to anticipate those, but not -- not the, you know, black swans like the recession, necessarily, but we do our best to anticipate what the future is going to look like and we make the most-prudent decision that we can, given the information that we have.

MR. MOYLE: I appreciate your -- your time. Thank -- thank you. I have no further questions.

CHAIRMAN GRAHAM: Staff, you change your mind?

MS. CRAWFORD: No, sir. No questions for this witness.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Clark.

COMMISSIONER CLARK: Thank you, Mr. Chairman. I -- I have a couple of questions for Mr. Borsch. Kind of in -- in line with Mr. Brew and Mr. Moyle's questions, I -- I have concerns about how we calculate capacity and how we allocate capacity of

new generation toward what our reserve requirements are.

Looking at -- so, one of the things that you stated was that, as we bring solar projects on, that what you're actually displacing is the future development of -- not a combined-cycle unit, but a peaker unit. I'm assuming you're talking about, like, a simple-cycle, a simple-cycle CT?

THE WITNESS: Yes.

COMMISSIONER CLARK: And so, in terms of capacity, if that's a peaking unit and your solar production does not give you full capacity count toward that, how do you displace a peaker with solar units?

THE WITNESS: Well, I think -- I think about it this way: you know, as we look at the reserve margin over time and the needed capacity on the peak over time, you know, load growth will cause us to decide that a new unit needs to be built in a particular year, for instance. And, you know, going forward, our load growth is modest enough that load growth alone would cause us to build, you know, mostly peakers because it would be, you know, in relatively-small increments. We have some combined cycles in our plan. They're mostly in

response to the expected retirement of large units, you know, in the 2030-and-beyond time frame.

So, when we look at those peakers and then we look at the addition of solar generation, we -- you know, you can say, well, you know, in this year, for instance, I might have only needed 40 or 50 megawatts, you know, to satisfy the peak, but in our typical planning process, we will look at what is a cost-effective way, not only to satisfy that year's peak, but also, you know, for years to come. So, we might build a 200-megawatt peaker in a given year, even though the actual need in that year might be less than a hundred megawatts.

So, effectively what happens when you add the solar, is you're saying, well, look, now I have an additional 85 megawatts of -- of peak capacity, so I didn't have to build that peaker in that year. I could wait three or four years before I need to actually build it.

COMMISSIONER CLARK: But doesn't that change the -- kind of to go back to Mr. Moyle's point here, doesn't that change what you've calculated in the CPVRR? Because now you're saying, okay, I'm dis- -- I was displacing it when I did my calculation and ran my numbers I was displacing a

peaker, but now that kind of has changed, I'm -- that's not actually what I'm displacing anymore, is it?

THE WITNESS: No, I think it is. And the way we look at it -- and again, you know, the methodology that we use is essentially to create a resource plan without -- starting without the projects in question -- in this case, the solar projects, and to determine, for that resource plan, what is the most effective way to add future generation.

Then we create a second plan, which has the subject projects in it -- in this case, the solar projects -- and we look and say, well, given that we have added this extra capacity in the beginning of the plan, you know, how would the other units space out in the plan. And then we just -- you know, essentially, we just compare the two of them to each other, both on a physical basis and a financial basis. And we say, you know, in these years in '26 through '29, for instance, I would have been paying the revenue requirements for the construction of a peaker that, now that I have the solar, I don't need to build that peaker until 2030. So, those revenue requirements can be saved.

COMMISSIONER CLARK: So, my second question has to do with the calculation on capacity factor, kind -- kind of in the same line. We keep talking capacity factor, but what we're actually talking about in terms of the 32 percent, is actually the amount of energy that's generated from the power output that's capable of that unit, correct?

THE WITNESS: Right. I mean, capacity factor really needs to be seen as the total amount of energy that a unit will produce across a year --

COMMISSIONER CLARK: Year's time.

THE WITNESS: -- divided by the, you know, total number of hours in a year times whatever the nameplate is.

COMMISSIONER CLARK: So -- so with my question, if you have 150 megawatts of capacity name -- of plate capacity, and you're calculating what your -- what you have towards your generation assets, how much of that 150 megawatts is calculated? You don't -- is -- is attributed to your -- to your peak requirement.

THE WITNESS: Ah, yes, that's -- that was the number that I gave earlier.

COMMISSIONER CLARK: That's not the 30- -- that's not the 32 percent --

THE WITNESS: No.
COMMISSIONER CLARK: -- that is the --
THE WITNESS: No. That -- the --
COMMISSIONER CLARK: -- actual capacity factor.
THE WITNESS: The value on the peak that we have calculated is 57 percent of the nameplate.
COMMISSIONER CLARK: 57 percent of the 150 megawatts actually is -- goes towards your peak contribution.
THE WITNESS: That's the percentage that we believe we can reliably count on, on the peak.
COMMISSIONER CLARK: Summer or winter?
THE WITNESS: Summer.
COMMISSIONER CLARK: Summer only.
THE WITNESS: Summer only.
COMMISSIONER CLARK: So, do you calculate the cost of having to also maintain or to build additional capacity? Or is that what you were talking about earlier; you're counting on that year-to-year change in what your needs are to be able to meet that future production needs later?
THE WITNESS: Right. We are -- we calculate that -- given that we have that increment, then, you know, we don't need a conventional generating

unit, which might not -- which might be, then, displaced further into the future by some number of years.

COMMISSIONER CLARK: Okay. I'll quit, Mr. Chairman.

CHAIRMAN GRAHAM: Okay.

Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman. And thank you, Mr. -- Commissioner Clark.

Just to follow up on the -- that line of questioning, if the solar is de- -- deferring -- and -- and you're essentially coming up with new future plan for power generation.

THE WITNESS: That's correct.

COMMISSIONER POLMANN: So, within -- you have an existing plan. You're going to impose a new quantity of solar generating capacity onto that. So, now you don't have the same need profile into the future.

THE WITNESS: That's correct.

COMMISSIONER POLMANN: So, you're -- you're sliding everything out.

THE WITNESS: Uh-huh.

COMMISSIONER POLMANN: And it turns out,

within reviewing that now, you're going to defer that peak -- peaking facility. That's -- one of those factors because of the size --

THE WITNESS: Uh-huh.

COMMISSIONER POLMANN: -- of the unit that you've now imposed, this solar.

The behavior or the -- the production profile of the solar facility appears, in our mind, perhaps, to not behave like a peaking facility. So, what is the matchup?

THE WITNESS: So -- and let me start from the point of view that -- let's think about the fact that our -- our summer peak, generally speaking, occurs and varies a little bit from year to year, but generally speaking, occurs in hour ending 4:00 or hour ending 5:00 p.m. in -- on a summer afternoon, typically an August afternoon.

So, we have looked at the projected behavior of those projects. And we -- as I mentioned earlier, we looked at -- at the top load bracket -- the top 10 percent of the loads across the anticipated year for those summer months, and then we matched those with what our anticipated solar performance was.

And you know, we -- as I say, we selected only

the bottom two-thirds for conservatism, but you know, essentially what we did was we said, well, this much solar is available during those hours. And you know, as I say, for conservatism, we down-rated it to the bottom two-thirds of that performance, but you know, we said we believe that we can reliably expect that solar will show up, you know, during these load hours.

COMMISSIONER POLMANN: Is it true that the -- a peaking unit -- this would be the gas-fired unit.

THE WITNESS: It would.

COMMISSIONER POLMANN: And that's available, regardless of the weather; is that correct?

THE WITNESS: Yes, absolutely.

COMMISSIONER POLMANN: And a solar-powered facility is more -- more available when the sun is shining.

THE WITNESS: More available when the sun shines.

COMMISSIONER POLMANN: Is it also true that your peak energy demand would be higher when the sun is shining, if this is a -- a summer peak.

THE WITNESS: Yes.

COMMISSIONER POLMANN: So, your presumption is that having a solar facility with a peak, sunny day

is -- is a reasonable bet; is that how this is --

THE WITNESS: That --

COMMISSIONER POLMANN: Rationale is working out?

THE WITNESS: That's, perhaps, a simplification, but yes is the answer to your question. You know, so, we look at a group of weather profiles. And there are certainly -- I mean, there are certainly days in which the load is, you know, high, within, you know, perhaps, a few percent of the peak, and the weather may not be sunny, so to speak, but you know, you may be getting only some small percentage of the solar performance. And those are -- that's factored into the average that we've got.

COMMISSIONER POLMANN: Okay. Continuing on the capacity factor, we -- in -- in earlier questioning, with the parties, there was a value of 29 to 30 percent --

THE WITNESS: Uh-huh.

COMMISSIONER POLMANN: -- that was discussed and -- with regard to cost-effectiveness.

When you look at the CPVRR, I'm assuming -- well, let me ask: What -- what capacity factor are you using when you're looking at CPVRR?

THE WITNESS: Well, the factors that are shown in the exhibit to my testimony are the first-year capacity factors. As I mentioned in response to one of the other questions, those do decline over time --

COMMISSIONER POLMANN: Yes.

THE WITNESS: -- with the assumed degradation of the projects. And so, that year-by-year, you know, energy production, as it declines a little bit over time, is taken into account across the whole life of the project in calculating the CPVRR.

COMMISSIONER POLMANN: Can you distinguish that those factors are in the 29- or 30-percent range as opposed to the 57-percent?

THE WITNESS: Well, those are completely different calculations. The 29- and 30-percent capacity factors are the -- you know, essentially an expression of the annual amount of energy that a unit will produce. The 57 percent is an estimation of the percentage of the nameplate that will be available at the time of the summer peak.

COMMISSIONER POLMANN: Let me rephrase. Cost-effectiveness of the solar unit, according to the -- this agreement that has an acronym that we will not speak of, relies on a CPVRR. So, you have

future costs and you bring those back to the present.

THE WITNESS: Yes.

COMMISSIONER POLMANN: What -- does that cost include a capacity factor?

THE WITNESS: Well, think about it this way: There are -- I mean, there are a number of components to how -- to the costs and savings, but you know, two of the biggest savings components in terms of the displacement of conventional generation by the solar are essentially the value of the capacity and the value of the energy.

So, the capacity factor, the 29-, 30-percent number that we're talking about here, is essentially a representation of the energy that's available from the solar plant to displace energy that would otherwise be generated from conventional generation. So, you can think of that as having displaced fuel costs and other associated operating costs from those conventional generating units.

The capacity-value number, the 57 percent, represents the opportunity for the solar to displace the capacity. So, think in terms of construction costs of future generating units. And each one of those is a significant component. And

they're broken out individually in one of the exhibits to my testimony.

As happens there -- well, I mean, in the base case, they're kind of on par with each other in the, you know, high-fuel and low-fuel cases, they begin to diverge -- or high-fuel-price and low-fuel-price cases.

COMMISSIONER POLMANN: Okay. One second, Mr. Chairman.

CHAIRMAN GRAHAM: Sure.

COMMISSIONER POLMANN: In answer to an earlier question, you -- in your Exhibit 4, the CPVRR through year 2050 -- in that table, there are a number of different line items -- this is a 30-year time period.

So, do the solar projects have a 30-year life or is this just a -- a depreciation period, including -- there are necessary replacement -- renewal and replacement components.

THE WITNESS: No, we believe that the solar project has a 30-year life based on the technical expectations. And Matt, perhaps, would have been better to answer this question, but based on the assurances and given by the manufacturers and relative -- recognizing that some of the components

like the inverters have to be replaced periodically over time, it is our expectation that the project has a 30-year technical life. And that's how we set the depreciation.

COMMISSIONER POLMANN: Okay. So, in terms of doing -- doing the analysis and -- and deriving the values that are in your Exhibit 4, whatever the costs are, including the -- if there are replacement components in any of those line items, does that include the replacement, the labor, whatever it is that -- that --

THE WITNESS: Yes.

COMMISSIONER POLMANN: -- will sustain the 30-year time period?

THE WITNESS: Yes.

COMMISSIONER POLMANN: So, it's an apples-to-apples comparison --

THE WITNESS: Yes.

COMMISSIONER POLMANN: -- to -- to survive to 2050.

THE WITNESS: That's correct.

COMMISSIONER POLMANN: All right. Thank you. That's all I have, Mr. Chairman.

CHAIRMAN GRAHAM: Okay. Redirect?

MS. TRIPLETT: No redirect. And I would ask

that Exhibits 11 through 14 be entered.

CHAIRMAN GRAHAM: If no objections, we will enter Exhibits 11 through 14 into the record.

(Whereupon, Exhibit Nos. 11 through 14 were admitted into the record.)

CHAIRMAN GRAHAM: Do you want to excuse this witness?

MS. TRIPLETT: Yes, please.

CHAIRMAN GRAHAM: We can do that.

MS. TRIPLETT: Thank you.

CHAIRMAN GRAHAM: All right. Mr. Moyle, in your opening statements, you requested five minutes to confer --

MR. REHWINKEL: Mr. Chair --

CHAIRMAN GRAHAM: -- with your colleagues.

MR. REHWINKEL: Before Mr. Moyle answers about five minutes, we've heard a lot today -- we learned a little bit that we didn't know. Public Counsel would request that we be given about 15 minutes to go confer with Mr. Moyle and Mr. Brew, and that we come back -- we're optimistic that it will be useful.

I would also request maybe two minutes to summarize before -- if -- if our discussions are fruitful, I would ask that you consider, based on

what we come back with, an opportunity to summarize in a way that would allow you to consider the option of a bench vote, if that makes sense, in lieu of setting this for briefing.

We feel like the -- the possibility of a bench vote is within reach. I don't know how Mr. Brew and Mr. Moyle feel about that, but that's -- that's the Public Counsel's view.

MR. MOYLE: Yeah, I think -- I think -- I think, at the opening, I had suggested some time to -- to talk. And I think this is consistent with that. It may be a couple of different conversations that are envisioned, but I think we've worked closely with -- with Duke on this and I think the benefit of a few minutes to talk may -- may benefit everybody at the end.

CHAIRMAN GRAHAM: Jennifer, Mary Anne, is there anything specific we have to do to consider that?

MS. HELTON: If I'm understanding Mr. Rehwinkel and Mr. Moyle correctly, I think what I'm hearing them say -- and correct me, please, if I'm wrong -- is that you all need 15 minutes to talk to decide whether you want to file a brief or not, and that, instead of filing a brief, you would

be -- the quid pro quo would be they want a couple of minutes' opportunity to address you again before staff were to make a verbal recommendation to you.

CHAIRMAN GRAHAM: Correct, but what does that do as far as Duke's rights to respond to that or to have their bite at the apple?

MS. HELTON: We would need to hear from Ms. Triplett to see whether she is agreeable to that process or not.

MR. REHWINKEL: Mr. Chairman, before she answers that, may I add that I would not ask for the right to summarize unless the recommendation of the group here is that -- that we allow you to make a bench vote.

CHAIRMAN GRAHAM: Yeah, I mean, I -- that was given.

MS. TRIPLETT: And anything that gets us to a bench vote is great by me because I do not like writing post-hearing briefs. You probably don't like reading them. But I'd just -- I would be ask that I be given the opportunity to speak last, just in case -- not that my friends to -- down the table would say anything that I would disagree with, but just to -- to give me a chance to clear anything up, but I -- I'm amenable to that process.

CHAIRMAN GRAHAM: Would you be -- would you be willing to roll that dice? They could completely change their mind by something you said.

MS. TRIPLETT: I asked to be invited to their meeting, but they said no.

(Laughter.)

CHAIRMAN GRAHAM: All right. So, if there's nothing legal that I need to do handle this, then we will break until 3:15 by that clock back there, and we'll give you guys your time when you get back.

(Brief recess.)

CHAIRMAN GRAHAM: All right. What say you all?

MR. REHWINKEL: Mr. Chairman, we had a fruitful meeting and we're -- we had a -- a meeting that allows us to ask for a couple of minutes maybe each to talk, to make remarks for your consideration in anticipation that you would be able to make a bench vote today.

CHAIRMAN GRAHAM: So, before we hear those comments, do we have to close the evidentiary record first?

MS. HELTON: Yes, sir, I think that would probably be wise to do that.

CHAIRMAN GRAHAM: Okay. So, we will close the evidentiary record.

MR. REHWINKEL: Thank you.

CHAIRMAN GRAHAM: Now --

MR. REHWINKEL: So, on behalf of the Public Counsel, we would like to state that we do not object to the Hamilton and Columbia projects at TEC- -- that Duke has brought forward for your consideration, nor do we object to the Commission making a decision today, based on the evidence that you've heard and that you have adduced in this hearing.

Having said that, there are some issues and concerns that we have about the presentation of this project. There is an eligibility criteria that was specifically included in the agreement for a purpose. And we have some concerns about whether Duke had met that, but we can't say that they didn't meet it. We can say that they presented evidence that they contend to you meets that burden.

And we're comfortable, under these circumstances, given the benefits that the projects have for customers, to say that we will ask the better questions in the next filing that's -- that

Duke has.

Specifically, our concerns are whether the -- there is an intent in the agreement that land-acquisition costs, whether they are present costs related to a purchase or a future stream of costs related to lease payments that give you control of the land, are supposed to be included in the ca- -- in the threshold number.

There was evidence presented that -- that, based on an assumed purchase price, they would meet that cap. The Commission can evaluate that evidence and -- and give it the weight it deserves.

Also, we are uncertain as to whether transmission costs are -- that Duke of Florida will incur because of this project are included or includible in the cap. Duke has presented evidence that they have included some costs, but not others, and then not-others-costs are not included in the revenue requirements for the duration of this agreement, but would, instead, be subject to litigation, potentially in -- in a future rate case.

In -- in summary, Commissioners, the number -- the 15- -- the 1,650 number is not a bill-to number; it is -- it is a threshold. Duke has filed

testimony that says they have configured this project such that it is -- it maximizes efficiency. And for purposes of this project we are satisfied that they have met their obligation there.

We do -- as we learn, as the Commission learns, we do think it is important that there be comparability among projects that all utilities that you regulate have. We think there's an apples-to-apples-to-prune comparison because here Duke did not bring a project that we think compares to the TECO example that we gave. It doesn't mean that they didn't meet their determination; it means it was hard to determine whether they did, but we'll expect better from them next time. And we will focus our efforts in the next SoBRA filing.

And that's all I have to say. Thank you.

CHAIRMAN GRAHAM: Mr. Brew?

MR. BREW: Thanks. Without going over the same grounds, we stand where we started, which is we don't oppose the projects, but we would like to see a whole lot more clarity in the total costs. There was a lot of digging that was required to figure out exactly what was included and what wasn't included that seemed unnecessary.

And there clearly needs to be a follow-up on

the actual performance that we get because there were a lot of questions today about capacity factor versus availability of peak. And that may not matter much right now with the two projects that we have, but it's going to pace -- place more of a strain on their fossil resources if they need more fast-start resources to cover for -- for solar than they are expecting.

One of the big differences is that intermittent generation is just that. It's so you have forecast areas you have to take into account, but you've got to have resources to back it up, and while that's not a problem here, it's something, we need to be mindful for it going forward, but certainly getting more clarity in the total costs should be an easier lift for the future filings.

Thanks.

CHAIRMAN GRAHAM: Thank you, sir.

Mr. Moyle.

MR. MOYLE: Thank you. And thank you for opportunity to have some conversations.

The law provides that a party can file a -- a brief. They have the right to file a brief and if any party wanted to exercise that, then it would go through a process whereby the briefs would be

filed. Your staff would put a recommendation and y'all would have to act on it, you know, six weeks from now or whenever.

FIPUG is comfortable waiving the right to -- to file that brief. So, we are not standing in the way of you all making a decision today, if that's what you desire.

I'll -- I'll make some comments a little different from -- from my colleagues, in that I think -- I think today's hearing was -- was useful and helpful in that there will be continued discussions about solar.

And from a -- a matter of state energy policy, I think these conversations are useful. There's a lot of -- of tough questions embedded in this and I think you all delved into some of them today. And I think that as -- as time goes forward, a lot of these issues probably warrant further -- further ex- -- exploration.

And one question, toward the end, that I would commend that you all consider is -- you know, we have a lot of cases before you. You have experts who are doing projections and analysis. And I think it would be quite informative if -- and I don't think it would be that hard to do -- is if

you just said, hey, could you give us a snapshot at -- you know, at year -- at year three, at year six, or some increments where -- where you have the ability to look and see whether these forecasts are -- are -- are sound or -- or off because you know, I think a lot of the decisions are being based on -- oh, there's -- it's going to save ratepayers money. I mean, sometimes it does, sometimes it doesn't. I know that that's an important factor, but I think, in terms of -- of your future decisions, that that might be something to consider to have some -- some bit of a follow-up mechanism on -- on, indeed, is this -- are the projections looking like they're tracking, are they close, or are they way off. And I think that would be informative. There is that requirement that certain projections be filed with the Commission about how the projects are performing, but a financial -- a similar financial analysis I don't think would be -- would be unwarranted given -- given the significance of -- of the proposition that you all are being presented with testimony that says, please approve this because this is going to save ratepayers money and -- and so, those are the comments that I'd like to share.

Thank you.

MS. TRIPLETT: Thank you. I will be brief. I -- I appreciate -- obviously, I am thankful that we are in -- hopefully in a position to -- for y'all to have a bench vote. And so, I appreciate that.

But I do feel compelled just to respond to a couple of the -- of the points that were made. I -- I do agree and think it was acknowledged that the evidence before you is that the -- the cost cap was demonstrated to be met. And I would disagree that there was any sort of -- I mean, they didn't say this, but just to the extent there was any implication that we hid the ball or we made it challenging to find where -- you know, whether the lease payments were included in the cost cap or whether network upgrades were -- were included -- we provided answers to staff discovery back in December. And that was the discussion that we had about going through and an- -- answering questions -- the witnesses answer questions about that discovery. And I think it pretty clearly shows that we did not include it, and there was a reason for that because the settlement agreement requires us to include construction costs. And --

and so, I know that we'll have future discussions in our future proceedings to the extent we continue to have leases and also, the treatment of -- of the transmission interconnection costs, but from our perspective, I think we did put forth all of the evidence, met our burden, and we look forward to having fur- -- further discussions. And I think, it won't be a surprise where Duke's position is on -- on -- on where those costs land.

And then, just on Mr. Moyle's comment on the -- follow-up on the forecast, I think that we just need to be mindful that, in our world, we -- prudence is a standard of what does a reasonable utility manager know at the time you are making the decision. And of course, that involves forecasting, and you use all of the reasonable information available to you. And I think we can all agree that the only thing right about a forecast is that it's going to be wrong, in some respects. And so, I would just caution that, to the extent -- this sounds a little bit like, well, let's go and, you know, see how things are going and how is that information to be used.

It -- it should not be inappropriately used to second-guess that decision because, of course, I

don't have the benefit of what's going to happen in five years, ten years. I'm sure Mr. Moyle wasn't suggesting that we do that, but I just wanted to say that for the record.

But now I've addressed all my concerns. And I also welcome the bench vote -- and of course, a bench vote of approving our projects.

And thank you very much.

CHAIRMAN GRAHAM: So, you wouldn't support the Bench vote if we didn't?

MS. TRIPLETT: Then I would write a really lengthy brief to try and convince you otherwise.

CHAIRMAN GRAHAM: Didn't you just waive your right to brief?

MS. TRIPLETT: Oh, no.

(Laughter.)

CHAIRMAN GRAHAM: Okay. Commissioners, this is our time to deliberate, to talk, to make comments, to persuade.

Commissioner Brown.

COMMISSIONER BROWN: Well, I think it is clear from evidence in the record and from the prefiled that Duke has met its -- satisfied its burden under the settlement agreement. These projects do diversify and strengthen Duke Energy Florida's

solar installments, which is good for customers which is good for the state.

There is a need. They kept beneath the cap -- the threshold, pardon me. And I think that it is in the public interest. With that -- if there are no questions, I would move approval of Issues 1 through 11, under Duke Energy Florida's position.

CHAIRMAN GRAHAM: It's been moved and seconded.

Further discussion, Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman. I appreciate Commissioner Brown's comments and -- and the motion. I also appreciate Duke's commitment to source diversity through these projects. It's an item that's -- I find of particular concern with all the utilities as we move forward.

I also appreciate Duke's continued efforts with solar energy. They've identified an ongoing effort looking at additional potential sites and projects. And in my review, also, of the evidence, all of evidence presented in the prefiled materials as well as here today, the Hamilton and Columbia solar projects are consistent with the 2017 agreement and I believe they'll provide meaningful

improvements to the Duke system on balance.

I also agree, in -- in my opinion, they're in the public interest and will provide real benefit. So, I would support -- support the mo- -- the motion and these projects.

Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Any further discussion, comments, questions, concerns?

I have to agree with -- with what Mr. Moyle said earlier about a follow-up for performance. And that's the reason why we're -- we have the reporting for this. Just like we've done, I guess an example would be for hedging. You know, you always look back every year to see how well you did. You know, you can't un-ring the bell, but at least you go back so, as you move forward, you continue to make informed decisions. And so, I think, with the data that we'll have coming in, each time with this, we can -- we have something we can look at. We have something to say, well, the capacity factor really didn't get to that point, or this really didn't show the way the witness said before. So, you can -- you can look at all those things as we move forward. So, I feel comfortable with this decision.

Anybody else? Okay.

Any further discussion?

Okay. All in favor, say aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

By your action, you have approved the Brown motion.

Are there any other matters to be addressed in this docket?

MS. CRAWFORD: Staff is aware of none. With the waiver of briefs and the bench vote, we'll simply note that the final order will be issued by April 22nd.

CHAIRMAN GRAHAM: Okay.

MR. REHWINKEL: Mr. Chairman, as a -- just a housekeeping matter, I believe I've been given all of the -- the confidential exhibits other than from Mr. -- well, I -- I believe I've given every -- received back all that I'm required to receive back.

So, just before the -- before we close, I just want to make sure that everyone has turned them back; that all we have is the court reporter's or any of the -- the parties who want to keep theirs, as they're entitled to do.

CHAIRMAN GRAHAM: Okay.

MR. REHWINKEL: Thank you.

MR. MOYLE: I -- I was graciously provided copies by Duke and returned them to Duke and told them I would sign a confidentiality agreement, if I had not, but -- and I will treat it all as confidential.

CHAIRMAN GRAHAM: Anyone else?

That all being said, we are and adjourned. Everybody, thank you for your time and your patience, and travel safe.

(Whereupon, proceedings concluded at 3:35 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, ANDREA KOMARIDIS, 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 11th day of April, 2019.

ANDREA KOMARIDIS
NOTARY PUBLIC
COMMISSION #GG060963
EXPIRES February 9, 2021