DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

July 1, 2020

VIA ELECTRONIC FILING

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

Re: *Review of 2020-2029 Storm Protection Plan Pursuant to Rule 25-6.030, F.A.C. Duke Energy Florida, LLC; Docket No. 20200069-EI*

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC ("DEF"), please find enclosed for electronic filing in the above-referenced docket, DEF's Rebuttal Testimony and Exhibit No. __ (JWO-6) of Jay W. Oliver and Rebuttal Testimony of Thomas G. Foster.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Matt.Bernier@duke-energy.com

MRB/cmw
Enclosures

<u>CERTIFICATE OF SERVICE</u>
Docket No. 20200069-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to the following by electronic mail this 1st day of July, 2020, to all parties of record as indicated below.

s/ Matthew R. Bernier
Attorney

C. Murphy / R. Dziechciarz Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 cmurphy@psc.state.fl.us rdziechc@psc.state.fl.us James W. Brew / Laura Wynn Baker 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007-5201 jbrew@smxblaw.com lwb@smxblaw.com	J.R. Kelly / Charles J. Rehwinkel Office of Public Counsel c/o The Florida Legislature 111 West Madison St., Rm. 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us Stephanie U. Eaton 110 Oakwood Dr., Ste. 500 Winston-Salem, NC 27103 seaton@spilmanlaw.com Derrick P. Williamson / Barry A. Naum 1100 Bent Creed Blvd., Ste. 101 Mechanicsburg, PA 17050 dwilliamson@spilmanlaw.com bnaum@spilmanlaw.com

IN RE: REVIEW OF 2020-2029 STORM PROTECTION PLAN PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200069-EI

REBUTTAL TESTIMONY OF
JAY W. OLIVER

JULY 1, 2020

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Jay W. Oliver. My current business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony supporting the Company's SPP on April 10, 2020.

Q. Has your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony to provide the Company's rebuttal to assertions and conclusions contained in the direct testimonies of OPC's witnesses Schultz and Norwood and Walmart's witness Perry. Mr. Foster will present additional rebuttal of Norwood and

Walmart's witness Perry. Mr. Foster will present additional rebuttal of the testimonies of OPC witness Schultz and the Company's rebuttal of Walmart witness Chriss.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring:

- Exhibit No. __ (JWO-6) is a composite exhibit consisting of select responses or responsive documents to OPC's Second Production of Documents and Eighth Set of Interrogatories:
    - POD 2-23 (20200069-DEF-000402-000404);
    - ROG 8-248 (20200069-DEF-003334-003335);
    - ROG 8-250 (20200069-DEF-003336-003337);
    - ROG 8-251 (20200069-DEF-003435);
    - ROG 8-253 (20200069-DEF-003436);
    - ROG 8-255 Response and (2020069-DEF-3340-3401); and
    - ROG 8-256 (20200069-DEF-003402-003404).

Q. Please summarize your testimony.

A. My testimony explains the more significant errors and misconceptions contained in Messrs. Norwood and Schultz's testimonies, and provides a brief response to Ms. Perry's. I have not attempted to rebut each, and every factual error or misconception contained in these testimonies but have rather concentrated on the overall conclusions and recommendations, though I will highlight the factual misunderstandings that underpin those faulty conclusions and recommendations as appropriate.

In short, Mr. Norwood provides a list of five "primary conclusions and recommendations" which are summarized and responded to below:

1. "DEF has not provided sufficient details supporting is Cost/Benefit Analyses for the SPP; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified."[1] This conclusion misconstrues the requirement that the Company include a "comparison of the costs … and the benefits" of the proposed storm protection programs. Rule 25-6.030(3)(d)4., F.A.C. Therefore, no formal "cost benefit analysis" is required by the Rule. Nevertheless, as demonstrated by the exhibits attached to my testimony, DEF did perform cost-benefit analyses to assist with prioritizing the projects and provided those detailed analyses to OPC in discovery.

2. "The estimated benefits included in DEF's CBA for the SPP are highly inflated by the assumption of distorted EWE ["extreme weather event"] outage reduction levels that are more than double the historical average level of EWE outages, and by inclusion of non-electric customer avoided lost revenues."[2] As I'll explain below, DEF used the 200-year HAZUS model to forecast EWE outage reduction levels, which is a much larger data set than that used by Mr. Norwood, who began his data set in 2006 and who advocates for disregarding the impacts of Hurricane Irma as an "outlier." DEF's approach is simply more robust and meaningful. DEF agrees that it included "non-electric" customer benefits as part of its analysis, but believes it is entirely appropriate to do so given the requirement of estimating benefits of SPP programs to customers and the recognition that the true value of receiving electric service is greater than the cost of the service, especially during and immediately after a storm.

[1] Norwood, p. 29, ll. 18-20.
[2] *Id.* at p. 29, l. 22 – p. 30, l. 2.

3. "DEF's CBA for the SPP did not evaluate potentially lower cost alternatives to the plan, such as delay or scaling back of the proposed $18.6 billion SPP."[3] This misconstrues the rule's requirement of "a description" of alternatives that could mitigate the resulting rate impact, which DEF provided with the original filing,[4] and creates a straw-man that can then be attacked. Again, the CBA is not required by the rule. Likewise, an evaluation of potentially lower-cost alternatives is not required by the rule. Not only does this argument miss the point, it also fails to appreciate that DEF's SPP was designed with rate impact very much at the forefront of consideration, hence the decision not to seek recovery of costs in 2020, followed by a very measured increase thereafter, all with the goal of meeting the legislature's long-term goal of providing additional storm hardening benefits to customers.

4. "DEF has provided high service reliability since 2006, with customers receiving service in 99.93% of all hours, including EWE outages. The forecasted improvement in reliability from the $6.6 billion is relatively small, and would likely increase annual reliability by less the 0.05%."[5] Fundamentally, this argument is directed against the policy approved by the legislature when it adopted the SPP statute – the legislature determined it was in the best interest of the citizens for additional storm hardening to take place; if Mr. Norwood disagrees, that contention should be brought to the legislature. Factually, Mr. Norwood has also cherry-picked sampling to assist with his point. Note that he points to the 10-year projected cost and his estimated of projected benefits, rather than the 30-year

[3] *Id.* at p. 30, ll. 3-5.
[4] Oliver, p. 13, ll. 4-13 (rev. April 14, 2020, revision provides page numbering originally omitted).
[5] Norwood, p. 30, ll. 6-9.

figures (cited previously when advantageous to his argument), which would include full-implementation of many of the programs and therefore greater benefits.

5. "Given the very high cost of the SPP initiative, and the fact that the plan is not urgently needed in its current magnitude, it would be prudent for DEF to delay the Plan until the economic impacts of the COVID-19 pandemic are more certain, and so that potentially less costly alternatives to the SPP can be evaluated."[6] Again, this argument, imbued with Mr. Norwood's evaluation that the SPP is "not needed", which runs counter to the legislature's express determination, fails to account for the fact that DEF's SPP purposefully took a measured approach to implementation. Moreover, it fails to recognize that COVID-19 has demonstrated that increased reliability is of even greater importance given the number of people working and educating their children from home.

Finally, Mr. Norwood recommends that the Commission "consider withholding full approval beyond year 2021 of DEF's proposed SPP pending the filing of an updated plan in 2022."[7] The Commission should reject this recommendation and approve DEF's SPP as filed. As noted above and discussed more thoroughly below, DEF's SPP complies with all requirements of the SPP statute and rule, appropriately balances the projected costs and estimated improvements to reliability and presents a measured implementation approach that is mindful of rate impacts to customers.

[6] *Id.* at ll. 10-13.
[7] *Id.* at ll. 17-18.

Mr. Schultz takes issue with DEF's cost estimation methodology, specifically pointing to perceived variances between estimated and actual costs; as I explain below, his testimony is based on information provided as a "snapshot in time" but when the estimated costs are compared to true actuals, it is readily apparent his concerns are without merit.

III. Witness Norwood

a. <u>Cost Benefit Analysis</u>

Q. Witness Norwood states "DEF has not provided details supporting its Cost/Benefit Analyses ('CBA') for the SPP; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified. This lack of transparency in DEF's CBA calculations is highly unusual for an investment of this magnitude." Can you please explain the SPP rule's requirement regarding providing costs and benefits with the SPP filing?

A. Yes. Per the SPP rule, DEF is required to provide "a description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability."[8] DEF fully complied with the SPP rule in the filing. In Exhibit JWO-2, DEF provided an estimate of both a reduction in restoration time and restoration costs from extreme weather events due to the implementation of the SPP. Additionally, DEF performed further cost benefit analyses in order to provide a prioritization of work to be completed through SPP that would further strengthen and harden the grid against extreme weather events.

[8] Rule 25-6.030(3)(b), F.A.C.

Q. Do you agree with Witness Norwood's contention that DEF has not provided details supporting its Cost/Benefit Analyses?

A**.** No, I do not. DEF has provided extensive information in discovery responses to the intervenors and Staff that includes the supporting details for the Cost/Benefit Analyses, CMI reductions, and outage cost reductions generated by the Guidehouse model used to assess the estimated impacts of the SPP (the model was described in detail in Exhibit No. JWO-4). This information was provided in DEF's responses to the following discovery requests (all issued by Public Counsel):

- Second Request for Production of Documents, numbers 23;
- Eighth Set of Interrogatories, numbers 248, 250, 251, 253, 255, and 256.

Exhibit No. __ (JWO-6) contains the select group of responses listed above to OPC's Second Set of Production of Documents and Eighth Set of Interrogatories and is included as an indicative example of the level of detail that was provided to OPC - detail which, as described above, goes beyond the level of detail required by the Rule.

Q. Please describe the CBA that DEF conducted through the engagement of Guidehouse and the output that was provided.

A. As discussed in my direct testimony, and further detailed in Exhibits JWO-2 and JWO-4 to that testimony, DEF engaged Guidehouse to create a model that estimated a reduction in restoration time and restoration costs from EWEs resulting from the implementation of DEF's SPP. The model also allowed for a prioritization of work over the life of the Programs based on prioritizing the highest benefit work first. This prioritization incorporated the probability of damage and consequence of damage to certain assets. As stated in Exhibit JWO-4, Appendix A, Guidehouse further details how the benefit-cost analysis (BCA) model "analyzes the benefits and costs of each relevant combination of program and location. The model uses outputs from the risk model and other information to simulate the expected present value of costs and benefits associated with each program." Section A.1.2 of Exhibit JWO-4 provides additional information on Guidehouse's detailed modeling approach and Appendix B provides details on the weather scenario modeling that "allows for simulated weather conditions and exposure probabilities to vary significantly depending on the latitude and longitude of each specific asset." As a result of the model, Guidehouse provided DEF with a model output that prioritizes work by SPP program based on the BCA model outputs and includes an estimate for reduction in restoration time and restoration cost.

Q. Please explain why non-electric benefits were included in the overall plan benefit calculation and why they should be included in the overall plan analysis.

A. Outages present inconvenience and difficulty for all customers, and it is important to account for the cost of interruptions borne by customers into planning decisions. Non-electric benefits were included in the benefit calculation to give a value to the customers' electric service. We did not look at other customer benefits streams such as societal benefits, economic development, healthcare, environmental benefits, property value, or the impact to Florida's GDP. This is a conservative approach when determining benefits and helps to keep the benefit cost ratio calculation relatively simple with only three benefit streams and two cost streams. See figure A-2 in Exhibit JWO-4 of DEF's filing.

Q. OPC witness Norwood states on page 15 of his testimony, "It is not appropriate to include such speculative non-electric benefits to justify a major electric utility investment such as the SPP." Do you agree?

A**.** No, I do not. The development of customer electric service interruption costs by the Lawrence Berkeley Lab and Nexant follows best practice guidelines[9], has been cited numerous times, and is used regularly to estimate the value of transmission and distribution system improvements to customers.

This non-electric benefit model has been used throughout the industry and in regulatory proceedings. Without doing an exhaustive search it can be found to have been used by Central Maine Power, CenterPoint Energy, and Indiana Power and Light.

Q. Based on the costs and benefits included in DEF's SPP filing, has DEF demonstrated that its SPP is cost effective and will reduce outage times and costs?

A**.** DEF's SPP filing, Exhibit No. JWO-2 lays out the benefits with respect to outage and cost reduction. This exhibit fully complies with the Rule's requirement and demonstrates that implementation of the SPP is cost effective and will reduce outage restoration times and costs. Moreover, although a cost benefit analysis of this type was not required by the Rule, DEF has provided in numerous Interrogatories cost benefit analysis output demonstrating the plan being cost beneficial to customers. Please refer to Exhibit No. __ (JWO-6) .

b. <u>DEF's CBA purportedly failed to evaluate potentially lower cost alternatives</u>

---

[9] *Available at* https://eta-publications.lbl.gov/sites/default/files/interruption_cost_estimate_guidebook_final2_9july2018.pdf, last visited June 22, 2020.

Q. Witness Norwood asserts that "DEF's CBA for the SPP did not evaluate potentially lower cost alternatives to the plan, such as delay or scaling back of the proposed $18.6 billion SPP."[10] Describe DEF's SPP alternatives that were considered to minimize and mitigate potential rate impact.

A. As explained in my direct testimony, DEF's proposed SPP has identified costs and benefits for each SPP program and believes there is value to our customers of implementing the entire 10-year scope. The only way DEF knows of reducing rate impact is to reduce spend. Reduced spend would result in less work accomplished and therefore less benefits achieved.

DEF believes the proposed SPP strikes a reasonable balance to minimize the rate impact over the first three years as we transition from the legacy Storm Hardening Plan (SHP) and Grid Investment Plan (GIP) included with the 2017 Settlement Agreement[11] into deploying the proposed SPP. In SPP year one (2020), there is no rate impact as it is focused on work associated with the approved SHP and GIP under the 2017 Settlement, with only minimal spend to prepare for SPP work to be implemented in 2021. In year two (2021), there is still a significant amount of on-going work being funded through existing base rates; DEF will also focus on beginning the transition to SPP work, which will result in a moderate estimated impact on rates (see page 40 of JWO-2). 2020 and 2021 allow a gradual transition in preparation for full SPP implementation in 2022. To reduce the 2022 rate impact, DEF would need to reduce the amount of work performed (and therefore spend) under its SPP. 2022 scope was developed to continue the measured

[10] Norwood, p. 30, ll. 3-5.

[11] *See* 2017 Revised and Restated Stipulation and Settlement Agreement, approved by Order No. PSC-2017-0451-AS-EU.

increase in SPP activities in a manner that DEF expects to be operationally feasible and deliver benefits to our customers.

c. <u>Reliability</u>

Q. Witness Norwood alleges that DEF's historical high T&D service reliability compared to other utilities in Florida, as well as the United States, necessitates the Commission require more analysis and justification before approval of DEF's SPP.[12] Do you agree with witness Norwood's apparent assertion that DEF's historical reliability undercuts the need for additional grid hardening?

A. No. Although DEF is proud of its historical reliability, DEF believes Mr. Norwood is making a policy argument that should be directed to the legislature. The Florida legislature has determined that it is in the best interest of the state for DEF and the other Florida utilities to strengthen the electric grid to better withstand the impacts of extreme weather events and improve overall service reliability; the legislature is fully aware of Florida utilities' historical reliability and made the policy decision that further strengthening of the grid should be undertaken. The Company filed its SPP as required by the SPP statute and as directed by Commission rule. Neither the legislation nor rule postulated a comparison to other utilities outside Florida as a precursor to determining if increased grid-strengthening should occur. Therefore, the comparison is simply not applicable in this case.

[12] *See* Norwood, p. 22, ll. 1-12.

Q. Witness Norwood states that "The forecasted improvement in reliability from the $6.6 billion SPP is relatively small and would likely increase annual reliability by less than 0.05%."[13] Do you agree with his conclusion?

A. No. Witness Norwood seems to be claiming that the "less than 0.05%" improvement attributed to the SPP will at best eliminate the impacts of extreme weather, as noted in Table 3 on page 21 of his testimony. The SPP is specifically focused on mitigating the effects of Extreme Weather Events ("EWEs"), such as Hurricane Irma which occurred in 2017. Based off the 14 years of data from 2006 to 2019, the average annual SAIDI including EWEs was 302 minutes. The 0.05% improvement noted by Witness Norwood would equate to approximately a 200 SAIDI minute annual reduction for DEF's customers, a 67% reduction in SAIDI minutes. DEF believes this would be a significant reduction that would benefit its customers.

Q. In response to a discovery request regarding Mr. Norwood's contention that DEF's SPP is forecasted to provide a "relatively small" improvement in reliability, OPC stated "a significant portion of the forecasted reduction in extreme weather outage time would likely occur in over-night and weekend time periods, or times when DEF's customers are away from their homes and businesses, and therefore would likely have little if any noticeable beneficial impact on customers."[14] How do you respond to this comment?

A. Asserting that DEF customers will feel "little if any noticeable beneficial impact" by having electricity during nights, weekends and while they are away from their homes or

[13] *Id.* at p. 30, ll. 7-9.

[14] OPC's Response to DEF's First Set of Interrogatories, number 44(b).

businesses is frankly incomprehensible. This comment is disconnected and uninformed as to the needs of Florida's citizens and businesses with regard to the importance of electric service and shows that OPC's sole concern when reviewing storm hardening, service reliability, and storm restoration efforts is the economic cost without regard to the benefits of these activities and the necessity of reliable electric service 24-hours a day. DEF's SPP filing is a well-thought-out plan that meets the intent of the Florida legislation while balancing costs and benefits to customers.

Q. Do you agree with Witness Norwood that DEF's forecast of future EWE outage time is nearly 3 times the level of historical EWE outage time since 2006, including the impacts of Hurricane Irma?[15]

A. No, I do not. The intent of the SPP is to prepare the grid for EWE and the 2006 to 2019 data window relied upon by Witness Norwood[16] provides an incomplete data set to analyze from an outage perspective. Reviewing DEF's Annual Service Reliability Reports and the history of EWE impacting the state over the period demonstrates the problem with relying on this limited data set: from 2006 to 2015, there were only 2 hurricanes (2008 Ike, 2012 Sandy) during that ten-year period that impacted DEF's service territory. Compare that to the two years preceding his sample (2004-2005) where DEF's service territory was impacted by 7 hurricanes (Charley, Frances, Ivan, Jeanne, Dennis, Katrina, and Wilma) and the four-years immediately following (2016 – 2019) where DEF's service territory was impacted by 5 hurricanes (Hermine, Matthew, Irma, Michael, and Dorian). For this more recent timeframe (2016-2019), DEF's forecast of

[15] *See id.* at pp. 17-18.
[16] *See, e.g., id.* at pp. 17, 18; Exhibit No.__ (SN-5).

future EWE outage time matches quite well with the average. Moreover, I will note that the customer minutes of interruption alone from just the 2004 named storms was approximately 5.2 billion minutes.

Rather than basing the plan on data from a 14-year window, DEF used the HAZUS model for EWE prediction, which provides strong modeling accuracy by encompassing 200 years of recorded hurricane paths and wind speeds, including the sample data set years listed above. This provides a comprehensive and unbiased analysis on the DEF system with respect to forecast duration, path, and intensity of severe weather events.

Q. Explain the basis of the extreme weather event assumptions used in the Guidehouse model and how that generated the extreme weather event outage time forecasts.

A. Guidehouse's analysis used FEMA's HAZUS-MH model to forecast duration, path, and intensity of severe weather events. Storm count, duration, and CMI was not evaluated for the 10-year historical period since this is too short a time horizon to escape random or systematic fluctuations and develop stable storm frequencies. Storm frequency was evaluated for the entire available Atlantic tropical storm data history (~200 years). Average tropical storm duration in DEF's service territory is ~23 hours. This is calculated from the NOAA HURDAT database of Atlantic tropic cyclones. Page B-2 in Appendix B of Exhibit JWO-4 provides the average probability of any given ~23-hour period falling into each storm category, over the territory, as a summary of the local probabilities derived from the HAZUS model by Guidehouse in the SPP analysis. These probabilities are constant over the forecast horizon for each scenario for each location.

This model is discussed in Appendix A and Appendix B of the Guidehouse report (Exhibit No. __ (JWO-4), as updated).[17]

Q. Do you believe OPC Witness Norwood's testimony is consistent with OPC Witness Mara's testimony filed in FPL's SPP Docket?[18]

A. No, I do not, as explained in more detail below.

Q. In referring to FPL's existing SHP programs, OPC Witness Mara states, "FPL presented an estimate of the reduction in restoration time and reduction in restoration costs from severe weather events such as hurricanes. These estimates were derived from FPL's storm assessment model which helps predict the damage of an incoming hurricane or tropical storm. This model can be used to estimated restoration assuming the storm hardening activity was not in place. The model uses a GIS model of the assets (poles and wires) and applies wind speeds. The model is calibrated based on actual storm data. With the modeled damage, estimates can be made on the restoration construction time and total duration." Did Duke Energy Florida take a similar approach for its SPP?

A. Yes, we did. Our model uses GIS and asset data and applies the 200-year HAZUS model of extreme weather events to simulate damage both with and without improvements. Using the 200-year HAZUS model DEF takes into consideration the law of large

[17] Additional detailed information on HAZUS-MH was provided in DEF's responses to OPC's Eighth Set of Interrogatories, numbers 243, 244, 249, and 250.

[18] Docket No. 20200071-EI, Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.

numbers in its modeling approach thereby strengthening model accuracy. Additionally, the model is calibrated based on actual storm impact data from DEF's territory.

Q. OPC Witness Mara also asserts that FPL should provide a similar analysis for its new SPP programs. Do you agree with Witness Mara that such an analysis would be appropriate for DEF?

A. Yes, I do. In fact, DEF did use its model to estimate benefits in this fashion for its eight new SPP programs.

Q. OPC Witness Mara notes on page 12 that FPL's SHP analysis assumed a return cycle of hurricanes Michael and Irma every three-years and five-years. He further recommended that FPL should use this approach to estimate benefits of its new SPP programs. In OPC testimony on DEF's SPP did OPC Witness Norwood recommend a similar approach?

A. He did not. If fact Witness Norwood recommends that the effects of Irma should be somehow "considered and adjusted" when estimating EWE outage impacts, and therefore anticipated benefits of DEF's SPP. On page 10 of his testimony he states, "the averaged impact of EWE outages was heavily influenced by Hurricane Irma, an historically rare Category 4 hurricane that occurred in 2017." In response to discovery asking why it would be reasonable to exclude Irma's impact when analyzing outage times, OPC responded that it did not advocate for excluding the effects of Irma, but that "Irma was a rare Category 4 Hurricane with a very low forecasted frequency of occurrence. Given these facts, it is appropriate to consider and adjust the historical average level of extreme weather outage impacts for the low frequency of Irma when evaluating the reasonableness of DEF's modeling of future extreme weather outage times."[19] Mr. Norwood's premise that Hurricane Irma was a "historically rare" occurrence is inaccurate as it pertains to DEF's system. Irma's recorded wind speeds in DEF's service territory varied between tropical storm and Category 2 levels on the Saffir-Simpson scale.[20]In fact, the likelihood of DEF experiencing weather similar to Irma, Tropical Storm to Category 2 force winds is not as historically rare as Witness Norwood indicates. Indeed, DEF is 804 times as likely to experience Tropical Storm force winds and eleven times as likely to experience Category 2 force winds, than Category 4 force winds. Therefore, it would be inappropriate to view the potential impact of a Hurricane Irma-type event as an outlier that should be "considered and adjusted" when forecasting the likelihood of future EWEs.

Q. Why would OPC Witness Norwood propose to eliminate Irma from benefit calculations while OPC Witness Mara proposes that FPL assume an Irma every 3 or 5 years to estimate the benefits of their future SPP programs?

A. I don't know. As mentioned above, it certainly seems the OPC is taking inconsistent positions between utilities.

Q. Do you agree with Witness Norwood that DEF has unreasonably skewed the outage reduction benefit of the SPP by including Hurricane Irma?

---

[19] OPC's Response to DEF's First Set of Interrogatories, Number 40(b).

[20] *See* DEF's 2017 Annual Service Reliability Report, p. 167.

A. I do not. In fact, I believe the law's intent is specifically directed at addressing extreme weather events such as Irma. Using the 200-year HAZUS model presents a significant sample of storm data rather than assuming an arbitrary frequency return of storms to calculate benefit data. In the context of extreme events, Irma is not an outlier, but an important data point on storm impacts on Florida customers.[21] It would be unwise to not include the most impactful storm in recent history on the DEF service territory when generating a projected benefit of reduced costs and outage durations. In fact, if DEF were to follow the guidance from the OPC given in Witness Mara's testimony, DEF believes benefit projections would likely be much greater.

d. <u>Customer Impact</u>

Q. Do you agree with Witness Norwood that DEF should delay implementation of the SPP due to COVID-19?

A. No. The Company filed its Storm Protection Plan as required by Florida Legislation and as directed by Commission rules and the procedural schedule. At no time during the process did the Commission halt or delay scheduling in this case. That said, DEF is cognizant of the SPP's economic impacts on customers, which is one of the reasons the company opted for a measured transition to SPP implementation, as witness Schultz correctly noted on page 7 of his testimony. Additionally, it is my belief that current conditions where many more customers are working from home emphasizes the need for the SPP. The time is now to invest in the grid in a way that enhances reliability for the many customers that are working remotely and supporting their children's educational

[21] DEF's responses to OPC's Seventh Set of Interrogatories, number 243, provides the probability of occurrence and frequency of future major storm events, and number 244 details the magnitude of major weather event impacts.

learning from home. Further, although the Company is working diligently to implement best practices to ensure the safety of its workers for storm-related duty under current conditions, proactively hardening the grid will still provide the optimal and safe conditions of all crew to ensure their health and safety throughout COVID-19. Every reinforced pole and wire will have cascading benefits and ensure that safe social distancing practices can occur. Perhaps grid reliability has never been so important during such times as these. The ten programs filed in this case will enhance reliability during extreme weather events and these investments are now even more important to support the economic recovery for Florida.

IV. Witness Schultz

a. Estimating Methodology & Variance

Q. On page 5 of his testimony, Witness Schultz states "Duke was requested in multiple interrogatories to explain in detail how the capitalized and O&M amounts on various pages of Exhibit No. (JWO-1) were determined. The responses were similar to the following response to Interrogatory No. 133[22] …. Clearly, this response is not a detailed explanation as it provides no specific details or determinations." Can you further explain the basis of capitalized and O&M amounts for 2020 work, as shown in Exhibit JWO-1?

---

[22] The interrogatory referred to by Witness Schultz, omitted from his testimony, along with the response, is provided here in full:

133. Refer to Exhibit No. (JWO-1), Pages 6-10. Please explain in detail how the capitalized amounts and O&M amounts were determined.

Response:

Capital unit cost consists of labor and materials based on historical averages and guidance from Finance for Indirect overheads. O&M is 1.25% of the Capital unit cost based on historical averages.

A. Yes, though I believe the original response provided a sufficient basis to understand how the costs were determined, especially given the high-level nature of the question being referenced (and I note that neither OPC nor any other party asked DEF to produce, for example, the historic labor and material costs included in the calculation). The estimates for capital and O&M work are determined based on historical costs of previously completed, similar projects or the vendor contract price. Where appropriate, the estimates consider whether internal crews or contractors will be used and if the work will be constructed with the facilities de-energized or energized (hot). The project team will take into consideration other aspects of the project that may impact costs such as matting, permitting, construction limitations, etc. The capitalized amount includes the design, permitting requirements, material, overhead allocations, and construction costs. The O&M amount is for the labor and associated costs for work such as transferring the wire during construction.

Q. Describe the process for developing costs per project.

A. To develop costs for projects, Project Management works with other internal organizations such as Asset Management, Resource Planners or Engineering to understand the scope and construction requirements of the work to be performed. Based on the requirements identified, Project Management works with Project Controls and Finance to estimate the project costs utilizing blended unit costs that consider if the work will be done with internal resources or contractors and if the work to be performed will be done de-energized or energized (hot). The estimated unit costs are based on a blended average of historical actual costs for previously constructed work of similar scope and construction methods, adjusted for known changes such as vendor contract price changes.

Since the estimated unit costs are based on an average, individual actual project costs will likely be higher or lower than the average depending on the factors of each specific location. The project team will take into consideration other aspects of the project that may impact costs such as matting, permitting requirements, construction limitations, etc.

Q. On pages 8 and 9 of his testimony, Witness Schultz provides a discussion showing his belief that the cost projections contained in Exhibit No. __ (JWO-1) appear to be overestimated when compared to historical costs provided in DEF's discovery responses. Can you please explain the differences in DEF's estimated costs for projects contained in Exhibit No. __(JWO-1) compared to the historical amounts for similar projects provided in discovery?

A. Yes, I will be happy to explain the perceived variance noted by Mr. Schultz. At the outset, it is important to note that Mr. Schultz is comparing estimated costs to actual costs at the point in time the information was provided, not necessarily the actual costs of a completed project. As these projects were recently placed in-service, but not yet closed, additional costs may be forthcoming as the projects move towards being closed to plant in-service. Examples of additional costs may include outstanding invoices and costs being charged to a blanket contract versus a specific contract, as well as costs to restore construction areas, complete final engineering drawings (as-builts), and/or removal of stub poles after joint use attachments have been relocated.

Q. Can you please explain DEF's process for estimating project costs, and why some level of cost variance is to be expected when looking at estimated versus actual costs at an individual project-level?

A. Yes. Distribution and Transmission estimated costs are based on a blended average of historical actual costs for previously constructed work of similar scope and construction methods, adjusted for known changes such as vendor contract price changes. Some variance between estimates and actuals per project is expected. Actuals may differ from estimates due to crew type availability (internal vs contractor), outage availability, materials costs, equipment costs, permitting requirements, matting costs, etc.

Q. On page 10, Witness Schultz indicates concern with estimated costs for work completed on "blue-sky" days and work completed during a storm restoration effort, and states "Clearly, without more explanation than has been provided by Duke so far, there is a problem with either the rate used during storm restoration or the estimates included in the current filing in this docket." Does Witness Schultz's testimony provide a valid comparison of these costs?

A. No. Mr. Schultz's comparison fails to account for how costs are tracked in a storm restoration setting versus normal "blue-sky" work, and it is important to understand the distinction and how it makes his comparison invalid.

Q. Can you please describe how costs are tracked and accounted for in a Storm response situation and how that process compares to the tracking and accounting of costs in non-storm response (i.e., "Blue Sky") scenarios?

A. Yes. The methodology used for calculating the pole replacement capital costs ($4,366 during Hurricane Michael and $4,248 during Tropical Storm Alberto) during extreme weather events is based on the replacement of a "typical pole" during non-extreme weather event restoration (i.e., "blue sky" restoration), and a "typical pole" is defined as a tangent pole without any equipment. However, during actual blue-sky restoration, most of the costs incurred are associated with the overhead distribution resources and material, but also include other costs such as vegetation crews, engineering, etc. Thus, while storm restoration costs are based on "typical poles", they fail to account for the bulk of costs associated with normal blue-sky work. Also not included in the pole replacement capital cost during extreme weather events are the logistics or damage assessment resources required to support the overhead resources. The pole replacement unit cost provided in Exhibit No. __ (JWO-1) ($8,273) is based on the historical actual costs of planned pole replacements over a two-year period, 2018 and 2019. These poles include countless variations, including tangents, dead ends, poles containing overhead equipment such as transformers and capacitors, poles with underground risers and terminations, etc. Included in these costs are engineering, permitting, site restoration, underground resources required to address underground cables, locates, and maintenance of traffic. Furthermore, replacing a pole on an energized circuit, as opposed to doing so during an outage event, requires additional safety measures due to the nature of working around high voltage lines.

Similar to poles, Mr. Schultz's utilization of the costs to replace wire during an extreme weather event[23] is not an appropriate comparison to DEF's Deteriorated Conductor program. The costs provided in Docket No. 20190110-EI represent all wire types, including secondary, streetlight and primary, and does not include any other material such as poles, insulators or anchors necessary to facilitate restoring the wires. Also not included in the wire replacement capital cost during extreme weather events are the

[23] Schultz, p. 11, ll. 1-12.

logistics or damage assessment resources required to support the overhead resources. When a Deteriorated Conductor project is completed, the primary and secondary wires, poles, insulators, anchors, transformers and other distribution equipment is replaced or brought up to current specifications. Included in the costs for these projects are engineering, permitting, site restoration, underground resources required to address underground cables, locates and maintenance of traffic. Furthermore, replacing overhead primary wires on an energized circuit, as opposed to doing so during an outage event, requires additional safety measure due to the nature of working around high voltage lines and keeping the existing conductor energized to maintain continuity of service to the customers.

V. Witness Perry

Q. Wal-Mart Witness Perry recommends that utilities work with Wal-Mart and other interested stakeholders on customer-sited generation that could potentially be used as part of future SPP filings. How does the Company respond?

A. Micro-grid technologies continue to evolve and advance and DEF welcomes the opportunity to discuss with Wal-Mart and other interested stakeholders their customer-sited generation ideas and potential solutions.

VI. Conclusion

Q. Mr. Oliver, your rebuttal covers a lot of ground, but did you respond to every contention regarding the company's proposed plan in your rebuttal?

A. No. Intervenor testimony on the SPP involved many pages of testimony and I could not reasonably respond to every single statement or assertion and, therefore, I focused on the issues that I thought were most important in my rebuttal testimony. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion.

Q. Does this complete your testimony?

A. Yes.

Discount Rate 7.61%

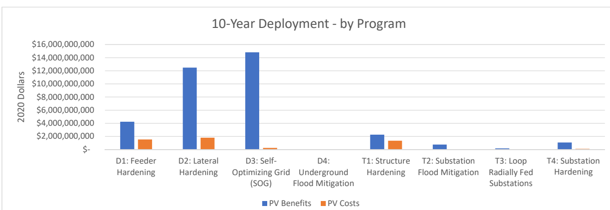
Step 1: Combine cost and benefit data for Non-Enabling Programs and Enabling Programs

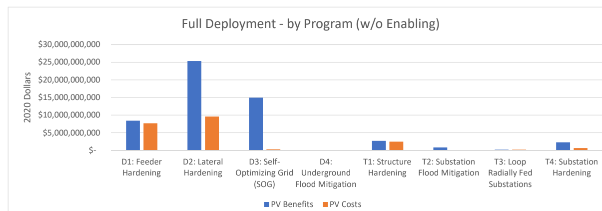
Program Category	Program (Normal)	Filing Program (Normal)	10-year PV Benefits	10-year PV Costs	Full Deployment PV Benefits	Full Deployment PV Costs	
Non-Enabling Programs - from "Master Output" tab	D1a: Feeder Hardening	D1: Feeder Hardening	$ 4,242,138,029	$ 1,524,387,923	$ 8,412,080,350	$ 7,679,151,162	
	D2a: Lateral Hardening (UG)	D2: Lateral Hardening	$ 10,712,715,262	$ 1,254,313,243	$ 21,819,728,839	$ 6,455,000,868	
	D2b: Lateral Hardening (OH)	D2: Lateral Hardening	$ 1,779,252,966	$ 560,861,004	$ 3,535,375,477	$ 3,155,156,049	
	D3: Self-Optimizing Grid (SOG)	D3: Self-Optimizing Grid (SOG)	$ 14,818,051,532	$ 255,628,341	$ 14,962,598,798	$ 298,336,842	
	D4: Underground Flood Mitigation	D4: Underground Flood Mitigation	$ 45,177,747	$ 10,805,349	$ 56,836,759	$ 26,831,352	
	T1a: Wood Pole Program (Prioritized)	T1: Structure Hardening	$ 520,815,305	$ 204,915,038	$ 520,815,305	$ 204,915,038	
	T1b: Wood Pole Program	T1: Structure Hardening	$ 1,117,092,729	$ 869,794,979	$ 1,291,991,649	$ 1,442,664,676	
	T2a: Tower Replacements	T1: Structure Hardening	$ 449,674,728	$ 152,479,820	$ 603,277,029	$ 260,331,400	
	T3: Overhead Ground Wires	T1: Structure Hardening	$ 178,659,682	$ 103,396,833	$ 250,357,662	$ 545,479,706	
	T4: Substation Flood Mitigation	T2: Substation Flood Mitigation	$ 762,511,417	$ 29,640,000	$ 820,533,683	$ 52,440,000	
	T5: Loop Radially Fed Substations	T3: Loop Radially Fed Substations	$ 167,430,977	$ 58,014,000	$ 193,809,228	$ 170,669,000	
	T6: Substation Hardening	T4: Substation Hardening	$ 1,074,843,735	$ 104,392,800	$ 2,267,602,211	$ 632,426,400	
Enabling Programs - from "Program Spend" tab	D1b: Pole Replacement and Treatment (Feeder)	D1: Feeder Hardening	$ -	$ 96,292,217	$ -	$ 96,292,217	
	D2c: Pole Replacement and Treatment (Lateral)	D2: Lateral Hardening	$ -	$ 247,608,557	$ -	$ 247,608,557	Spend for Enabling
	D3b: Self-Optimizing Grid (SOG) - C&C	D3: Self-Optimizing Grid (SOG)	$ -	$ 118,376,002	$ -	$ 118,376,002	Programs is not available
	T1c: Structure Inspections	T1: Structure Hardening	$ -	$ 2,168,080	$ -	$ 2,168,080	after 2029; therefore the
	T2b: Tower Drone Inspections	T1: Structure Hardening	$ -	$ 666,695	$ -	$ 666,695	full deployment cost only
	VM1: Distribution VM	VM1: Distribution VM	$ -	$ 272,675,510	$ -	$ 272,675,510	considers the spend from
	VM2: Transmission VM	VM2: Transmission VM	$ -	$ 113,433,180	$ -	$ 113,433,180	2020-2029

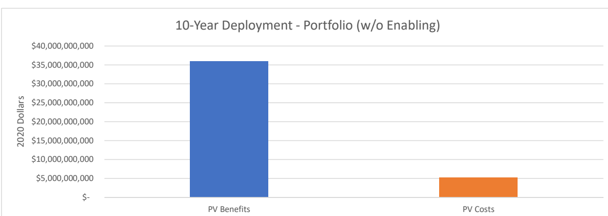
Step 2a: Generate data to feed graphs (NOT INCLUDING enabling programs)

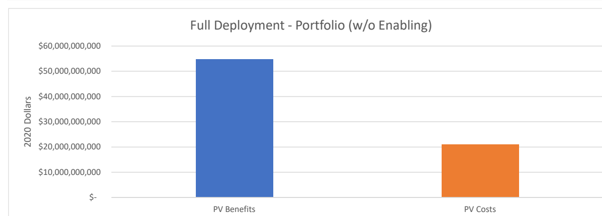
	10-Year				Full Deployment			
Program	PV Benefits	PV Costs	NPV	B/C Ratio	PV Benefits	PV Costs	NPV	B/C Ratio
D1: Feeder Hardening	$ 4,242,138,029	$ 1,524,387,923	$ 2,717,750,105	2.78	$ 8,412,080,350	$ 7,679,151,162	$ 732,929,189	1.10
D2: Lateral Hardening	$ 12,491,968,228	$ 1,815,174,247	$ 10,676,793,981	6.88	$ 25,355,104,316	$ 9,610,156,917	$ 15,744,947,399	2.64
D3: Self-Optimizing Grid (SOG)	$ 14,818,051,532	$ 255,628,341	$ 14,562,423,191	57.97	$ 14,962,598,798	$ 298,336,842	$ 14,664,261,956	50.15
D4: Underground Flood Mitigation	$ 45,177,747	$ 10,805,349	$ 34,372,398	4.18	$ 56,836,759	$ 26,831,352	$ 30,005,407	2.12
T1: Structure Hardening	$ 2,266,242,443	$ 1,330,586,670	$ 935,655,773	1.70	$ 2,666,441,644	$ 2,453,390,820	$ 213,050,824	1.09
T2: Substation Flood Mitigation	$ 762,511,417	$ 29,640,000	$ 732,871,417	25.73	$ 820,533,683	$ 52,440,000	$ 768,093,683	15.65
T3: Loop Radially Fed Substations	$ 167,430,977	$ 58,014,000	$ 109,416,977	2.89	$ 193,809,228	$ 170,669,000	$ 23,140,228	1.14
T4: Substation Hardening	$ 1,074,843,735	$ 104,392,800	$ 970,450,935	10.30	$ 2,267,602,211	$ 632,426,400	$ 1,635,175,811	3.59
Total	***$ 35,868,364,108***	***$ 5,128,629,331***	***$ 30,739,734,777***	***6.99***	***$ 54,735,006,989***	***$ 20,923,402,492***	***$ 33,811,604,497***	***2.62***

Note: Present values for distribution programs are calculated over a 30-year analysis horizon; transmission programs are over 40 years.





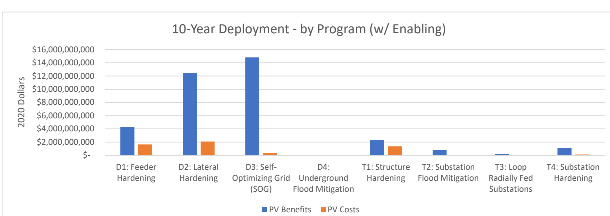


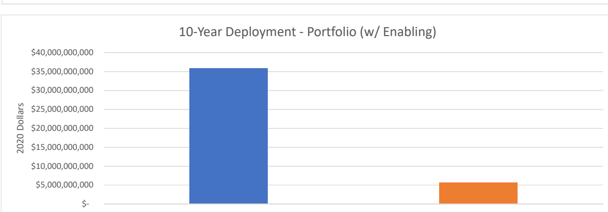


Step 2b: Generate data to feed graphs (INCLUDING enabling programs)

	10-Year			
Program	PV Benefits	PV Costs	NPV	B/C Ratio
D1: Feeder Hardening	$ 4,242,138,029	$ 1,620,680,140	$ 2,621,457,889	2.62
D2: Lateral Hardening	$ 12,491,968,228	$ 2,062,782,804	$ 10,429,185,424	6.06
D3: Self-Optimizing Grid (SOG)	$ 14,818,051,532	$ 374,004,344	$ 14,444,047,188	39.62
D4: Underground Flood Mitigation	$ 45,177,747	$ 10,805,349	$ 34,372,398	4.18
T1: Structure Hardening	$ 2,266,242,443	$ 1,333,421,445	$ 932,820,998	1.70
T2: Substation Flood Mitigation	$ 762,511,417	$ 29,640,000	$ 732,871,417	25.73
T3: Loop Radially Fed Substations	$ 167,430,977	$ 58,014,000	$ 109,416,977	2.89
T4: Substation Hardening	$ 1,074,843,735	$ 104,392,800	$ 970,450,935	10.30
Total	***$ 35,868,364,108***	***$ 5,593,740,882***	***$ 30,274,623,226***	***6.41***

Note: Present values for distribution programs are calculated over a 30-year analysis horizon; transmission programs are over 40 years.





Reduced CMI

Category	Total	D1: Feeder Hardening	D2: Lateral Hardening	D3: Self-Optimizing Grid (SOG)	D4: Underground Flood Mitigation	T1: Structure Hardening	T2: Substation Flood Mitigation	T3: Loop Radially Fed Substations	T4: Substation Hardening
High Wind | Tropical Storm	216,051,717	16,259,261	96,560,578	96,624,141	-	3,649,483	-	36,139	2,922,115
High Wind | Cat 1	119,449,281	10,477,863	52,637,774	51,399,595	-	3,264,783	-	40,838	1,628,427
High Wind | Cat 2	48,812,554	4,645,281	21,138,607	20,529,718	-	1,800,689	-	27,613	670,645
High Wind | Cat 3	38,232,401	3,782,848	15,743,975	16,030,637	-	2,106,455	-	33,539	534,947
High Wind | Cat 4	17,957,715	1,639,690	6,776,060	7,673,168	-	1,562,597	-	29,939	276,261
High Wind | Cat 5	5,332,854	336,839	1,714,153	2,561,491	-	444,906	-	41,779	233,686
Flood | Any	2,268,487	149,456	190,261	1,483	3,823	-	1,906,966	16,491	7
Storm Surge | Any	9,354,940	1,341,434	1,245,903	1,529	436,335	-	6,160,730	168,988	22
Total	457,459,949	38,632,673	196,007,311	194,821,764	440,158	12,828,912	8,067,696	395,326	6,266,110

Reduced SAIDI

Category	Total	D1: Feeder Hardening	D2: Lateral Hardening	D3: Self-Optimizing Grid (SOG)	D4: Underground Flood Mitigation	T1: Structure Hardening	T2: Substation Flood Mitigation	T3: Loop Radially Fed Substations	T4: Substation Hardening
High Wind | Tropical Storm	115.27	8.67	51.52	51.55	-	1.95	-	0.02	1.56
High Wind | Cat 1	63.73	5.59	28.08	27.42	-	1.74	-	0.02	0.87
High Wind | Cat 2	26.04	2.48	11.28	10.95	-	0.96	-	0.01	0.36
High Wind | Cat 3	20.40	2.02	8.40	8.55	-	1.12	-	0.02	0.29
High Wind | Cat 4	9.58	0.87	3.62	4.09	-	0.83	-	0.02	0.15
High Wind | Cat 5	2.85	0.18	0.91	1.37	-	0.24	-	0.02	0.12
Flood | Any	1.21	0.08	0.10	0.00	0.00	-	1.02	0.01	0.00
Storm Surge | Any	4.99	0.72	0.66	0.00	0.23	-	3.29	0.09	0.00
Total	244	21	105	104	0	7	4	0	3

Notes:
Based on projects deployed over the 10-year study period
The SAIDI reduction value in this tab is based on a customer count from 2020 (1,874,269; from "psc_feeder_customer_type_report_01082020.xlsx")
All values based on the Average Storm Frequency weather scenario

Outage Restoration Cost

Category	Total	D1: Feeder Hardening	D2: Lateral Hardening	D3: Self-Optimizing Grid (SOG)	D4: Underground Flood Mitigation	T1: Structure Hardening	T2: Substation Flood Mitigation	T3: Loop Radially Fed Substations	T4: Substation Hardening
High Wind | Blue Sky	1,542,296	356,102	1,159,762	-	-	17,347	-	-	9,085
High Wind | Tropical Storm	22,148,142	1,571,931	9,954,366	-	-	10,621,844	-	-	-
High Wind | Cat 1	9,915,088	951,727	5,843,546	-	-	3,119,775	-	-	40
High Wind | Cat 2	3,901,861	407,550	2,514,377	-	-	979,854	-	-	80
High Wind | Cat 3	3,074,404	322,433	2,061,178	-	-	690,414	-	-	379
High Wind | Cat 4	1,498,369	136,199	1,013,560	-	-	347,259	-	-	1,351
High Wind | Cat 5	431,029	26,662	326,189	-	-	67,291	-	-	10,887
Flood | Any	111,236	0	62,418	-	8,031	-	40,787	-	-
Storm Surge | Any	1,607,127	(0)	452,193	-	896,594	-	258,340	-	-

Notes:
Based on projects deployed over the 10-year study period
Values represent average outage restoration costs per year (2020 dollars), includes both capital and O&M
All values based on the Average Storm Frequency weather scenario

Duke Energy Florida, LLC
Docket no. 20200069-EI
Witness: Oliver
Exhibit No. ____(JWO-6)

Program	Costs (Deployment Costs)			CMI Reduction			Outage Restoration Cost Benefits		
	Normal	Above Avg	Increased	Normal	Above Avg	Increased	Normal	Above Avg	Increased
D1: Feeder Hardening	$ 1,524,387,923	$ 1,524,387,923	$ 1,524,387,923	38,632,673	42,495,940	48,290,841	$ 3,416,502	$ 3,758,152	$ 4,270,628
D2: Lateral Hardening	$ 1,815,174,247	$ 1,815,174,247	$ 1,815,174,247	196,007,311	215,608,042	245,009,139	$ 22,227,827	$ 24,450,610	$ 27,784,784
D3: Self-Optimizing Grid (SOG)	$ 255,628,341	$ 255,628,341	$ 255,628,341	194,821,764	214,303,940	243,527,205	$ -	$ -	$ -
D4: Underground Flood Mitigation	$ 10,805,349	$ 10,805,349	$ 10,805,349	440,158	484,173	550,197	$ 904,625	$ 995,087	$ 1,130,781
T1: Structure Hardening	$ 1,330,586,670	$ 1,330,586,670	$ 1,330,586,670	12,828,912	14,111,803	16,036,140	$ 15,826,437	$ 17,409,081	$ 19,783,046
T2: Substation Flood Mitigation	$ 29,640,000	$ 29,640,000	$ 29,640,000	8,067,696	8,874,465	10,084,619	$ 299,127	$ 329,040	$ 373,909
T3: Loop Radially Fed Substations	$ 58,014,000	$ 58,014,000	$ 58,014,000	395,326	434,858	494,157	$ -	$ -	$ -
T4: Substation Hardening	$ 104,392,800	$ 104,392,800	$ 104,392,800	6,266,110	6,892,721	7,832,637	$ 12,737	$ 14,010	$ 15,921
	Costs include capital, O&M, and removal			*Includes reduced CMI from storm and blue sky*			*Includes reduced restoration costs from storm and blue sky*		

Notes
Based on projects deployed over the 10-year study period
Costs include capital, O&M, and removal
Reduced CMI includes impacts during storm conditions only (excludes blue sky)
Outage restoration cost benefits include impacts during storm conditions only (excludes blue sky)

Program	(a) CMI Benefit	(b) Restoration Cost Benefit	('c) Life-cycle Gross Benefit	(d) Life-cycle Net Benefit		(e2) Life-cycle B/C w/o ICE	Life-cycle Costs	Life-cycle Benefits w/o ICE
D1: Feeder Hardening	4,016,326,192	$ 3,772,604	$ 4,242,138,029	$ 2,717,750,105	2.78	0.15	$ 1,524,387,923	$ 225,811,837
D2: Lateral Hardening	11,332,116,439	$ 23,387,590	$ 12,491,968,228	$ 10,676,793,981	6.88	0.64	$ 1,815,174,247	$ 1,159,851,789
D3: Self-Optimizing Grid (SOG)	14,818,051,532	$ -	$ 14,818,051,532	$ 14,562,423,191	57.97	-	$ 255,628,341	$ -
D4: Underground Flood Mitigation	29,221,879	$ 904,625	$ 45,177,747	$ 34,372,398	4.18	1.48	$ 10,805,349	$ 15,955,869
T1: Structure Hardening	1,462,441,611	$ 15,843,784	$ 2,266,242,443	$ 935,655,773	1.70	0.60	$ 1,330,586,670	$ 803,800,832
T2: Substation Flood Mitigation	755,657,764	$ 299,127	$ 762,511,417	$ 732,871,417	25.73	0.23	$ 29,640,000	$ 6,853,653
T3: Loop Radially Fed Substations	166,759,807	$ -	$ 167,430,977	$ 109,416,977	2.89	0.01	$ 58,014,000	$ 671,170
T4: Substation Hardening	1,067,738,596	$ 21,822	$ 1,074,843,735	$ 970,450,935	10.30	0.07	$ 104,392,800	$ 7,105,139

Notes:
Based on projects deployed over the 10-year study period
All values based on the Average Storm Frequency weather scenario
All values are present values (2020 dollars) over the assumed useful lifetime (30 years for distribution, 40 years for transmission)
(b) restoration cost benefits include both MED and non-MED

ROG 8-255. Please provide the benefit/cost ratio for each selected SPP project with and without monetized CMI (ICE Calculator-based outage reduction values).

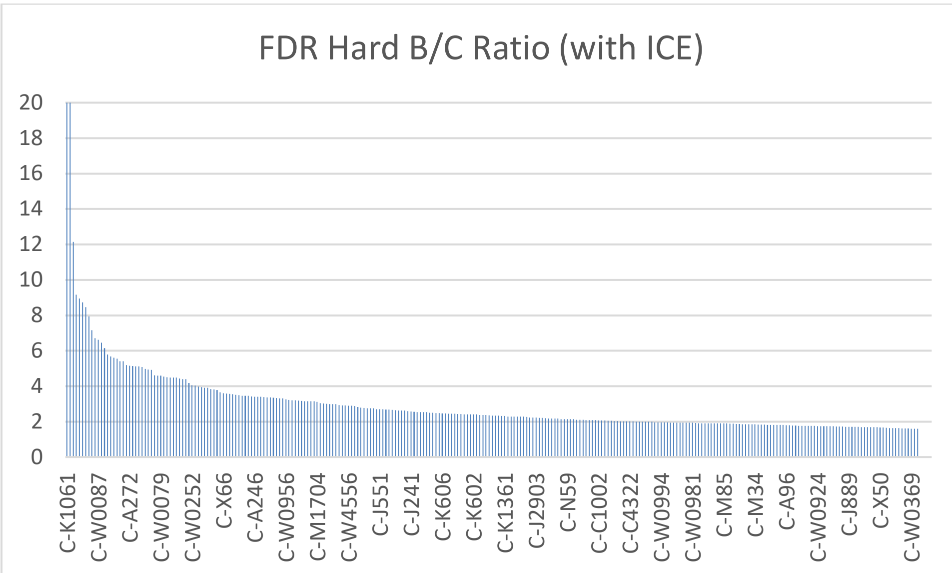
Response:
Subject to and without waiving the objections filed on May 11, 2020, the attached charts show the benefit/cost ratio for each of the SPP project with and without monetized CMI reduction. Prioritization is based on all benefit streams. Further prioritization adjustment is expected based on subject matter expertise, resource availability, or other regional impacts.

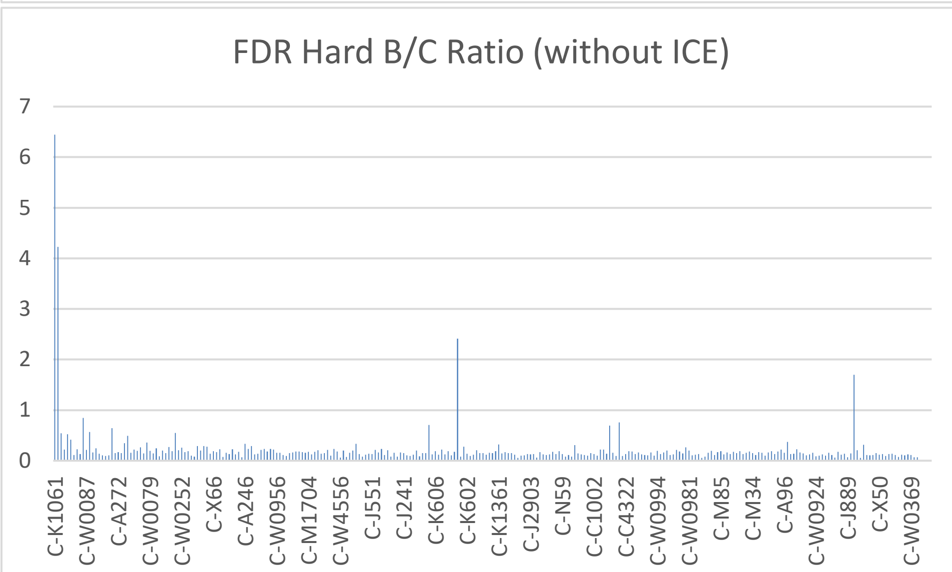
The benefit from completion of the SOG program is a reduction of customers affected by long duration outages and does not eliminate an outage, therefore there is no benefit calculated without customer benefits. Circuits without CMI reduction potential have low to zero BC ratios or have partial or full SOG implementation in place since we are a few years into the program.

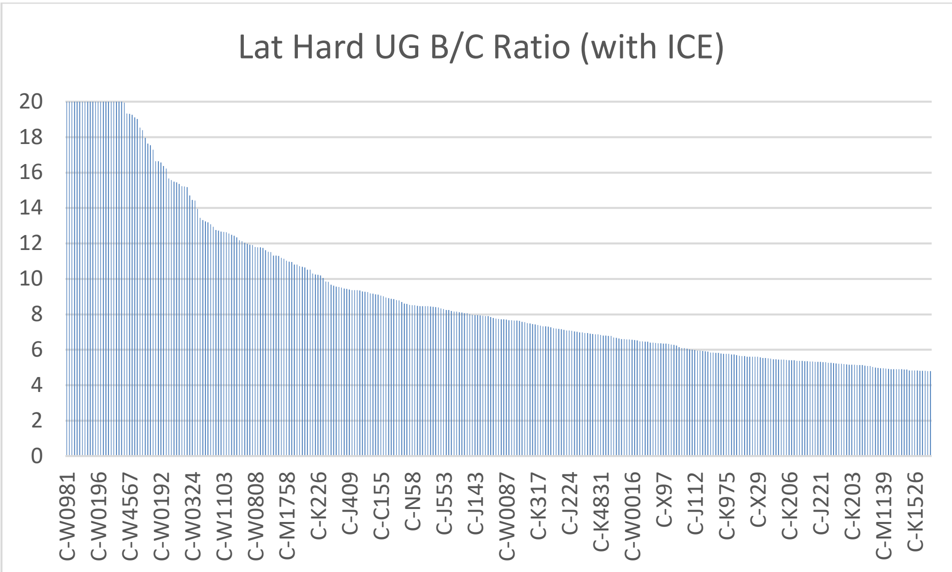
The benefit from completion of the Loop Radially Fed Substations program is a reduction of customers affected by long duration outages and does not eliminate an outage, alternately provides a secondary source to switch to much like SOG.

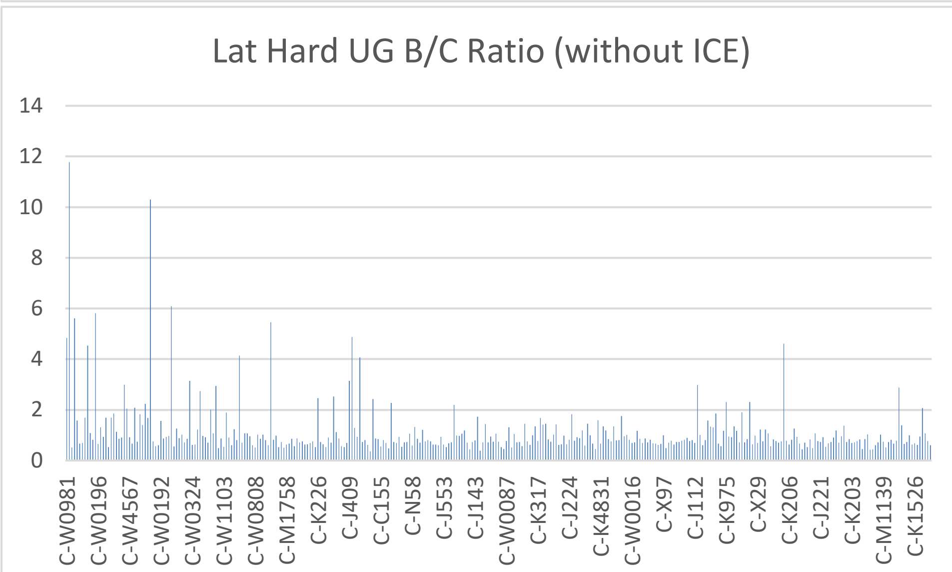
Note: Not all project labels fit within the x-axis due to the volume of projects, please see attached documents bearing bates numbers 20200069-DEF-003340 through 20200069-DEF-003401, for full list.

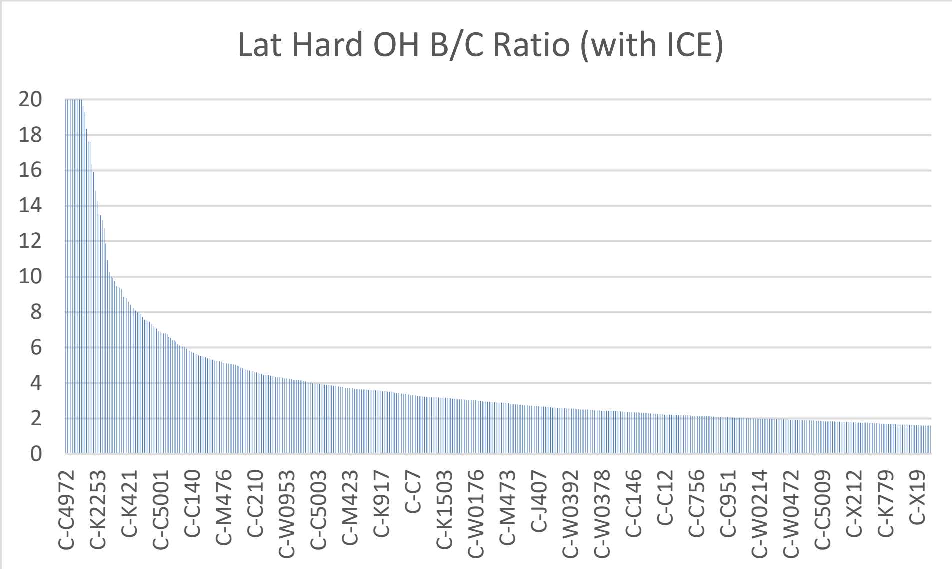
The program CBA charts below have been updated to reflect the modeling change and show the effects on the CBA.

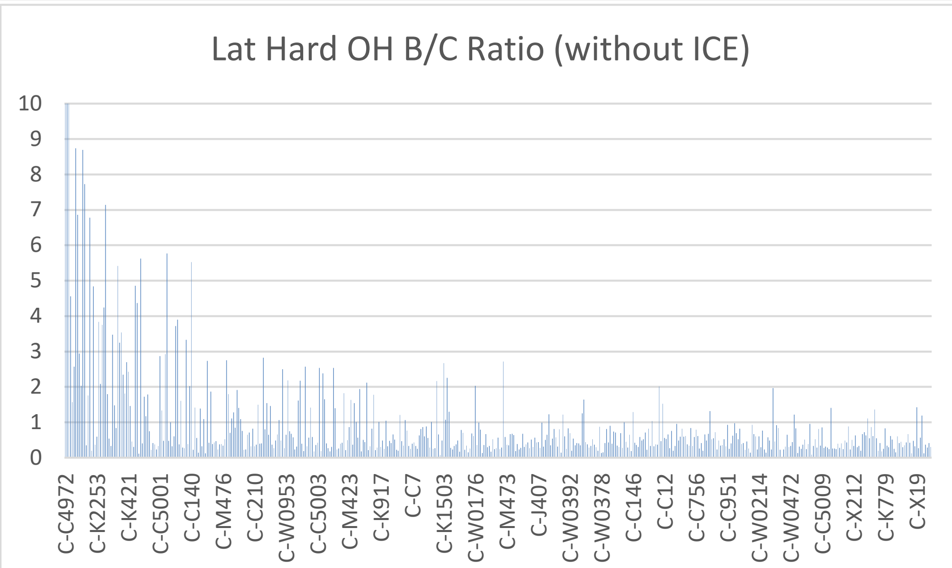

FDR Hard B/C Ratio (with ICE)
20
18
16
14
12
10
8
6
4
2
0
C-K1061
C-W0087
C-A272
C-W0079
C-W0252
C-X66
C-A246
C-W0956
C-M1704
C-W4556
C-J551
C-J241
C-K606
C-K602
C-K1361
C-J2903
C-N59
C-C1002
C-C4322
C-W0994
C-W0981
C-M85
C-M34
C-A96
C-W0924
C-J889
C-X50
C-W0369

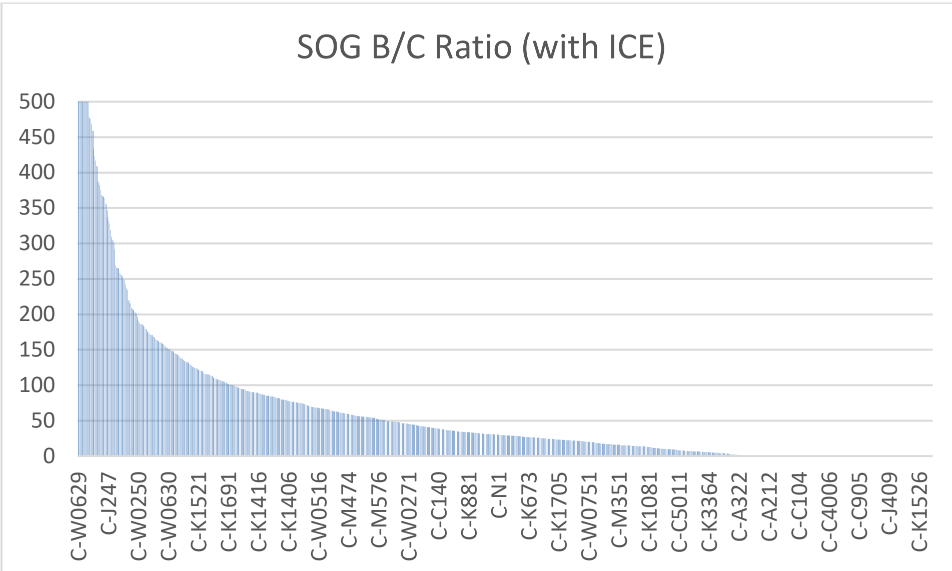

FDR Hard B/C Ratio (without ICE)
7
6
5
4
3
2
1
0
C-K1061
C-W0087
C-A272
C-W0079
C-W0252
C-X66
C-A246
C-W0956
C-M1704
C-W4556
C-J551
C-J241
C-K606
C-K602
C-K1361
C-J2903
C-N59
C-C1002
C-C4322
C-W0994
C-W0981
C-M85
C-M34
C-A96
C-W0924
C-J889
C-X50
C-W0369

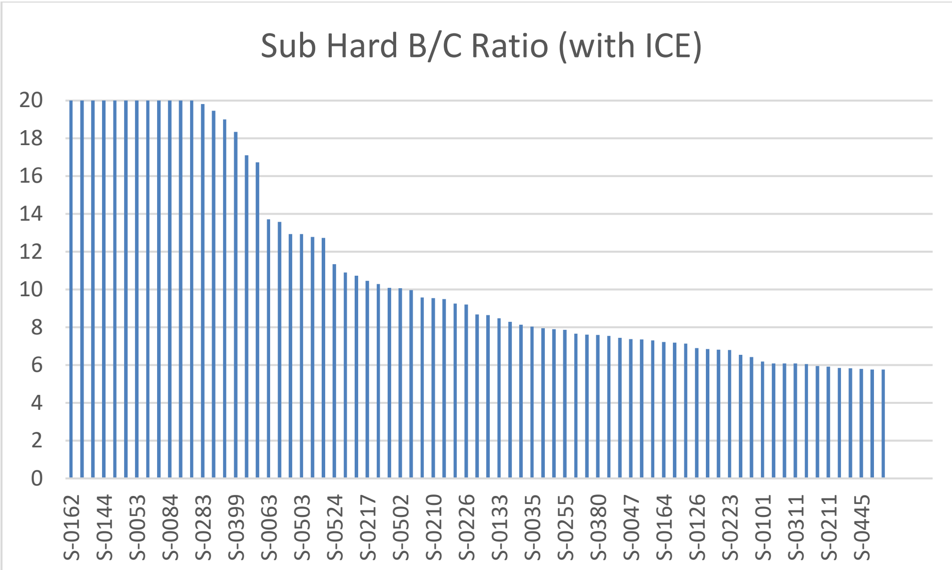

Lat Hard UG B/C Ratio (with ICE)
20
18
16
14
12
10
8
6
4
2
0
C-W0981
C-W0196
C-W4567
C-W0192
C-W0324
C-W1103
C-W0808
C-M1758
C-K226
C-J409
C-C155
C-N58
C-J553
C-J143
C-W0087
C-K317
C-J224
C-K4831
C-W0016
C-X97
C-J112
C-K975
C-X29
C-K206
C-J221
C-K203
C-M1139
C-K1526

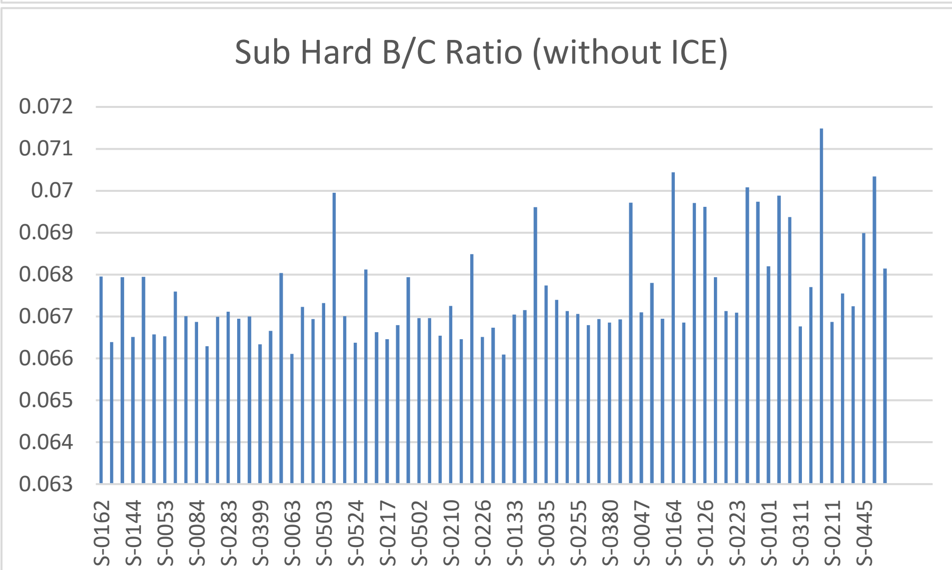

Lat Hard UG B/C Ratio (without ICE)
14
12
10
8
6
4
2
0
C-W0981
C-W0196
C-W4567
C-W0192
C-W0324
C-W1103
C-W0808
C-M1758
C-K226
C-J409
C-C155
C-N58
C-J553
C-J143
C-W0087
C-K317
C-J224
C-K4831
C-W0016
C-X97
C-J112
C-K975
C-X29
C-K206
C-J221
C-K203
C-M1139
C-K1526


Lat Hard OH B/C Ratio (with ICE)
20
18
16
14
12
10
8
6
4
2
0
C-C4972
C-K2253
C-K421
C-C5001
C-C140
C-M476
C-C210
C-W0953
C-C5003
C-M423
C-K917
C-C7
C-K1503
C-W0176
C-M473
C-J407
C-W0392
C-W0378
C-C146
C-C12
C-C756
C-C951
C-W0214
C-W0472
C-C5009
C-X212
C-K779
C-X19


Lat Hard OH B/C Ratio (without ICE)
10
9
8
7
6
5
4
3
2
1
0
C-C4972
C-K2253
C-K421
C-C5001
C-C140
C-M476
C-C210
C-W0953
C-C5003
C-M423
C-K917
C-C7
C-K1503
C-W0176
C-M473
C-J407
C-W0392
C-W0378
C-C146
C-C12
C-C756
C-C951
C-W0214
C-W0472
C-C5009
C-X212
C-K779
C-X19


SOG B/C Ratio (with ICE)
500
450
400
350
300
250
200
150
100
50
0
C-W0629
C-J247
C-W0250
C-W0630
C-K1521
C-K1691
C-K1416
C-K1406
C-W0516
C-M474
C-M576
C-W0271
C-C140
C-K881
C-N1
C-K673
C-K1705
C-W0751
C-M351
C-K1081
C-C5011
C-K3364
C-A322
C-A212
C-C104
C-C4006
C-C905
C-J409
C-K1526


Sub Hard B/C Ratio (with ICE)
20
18
16
14
12
10
8
6
4
2
0
S-0162
S-0144
S-0053
S-0084
S-0283
S-0399
S-0063
S-0503
S-0524
S-0217
S-0502
S-0210
S-0226
S-0133
S-0035
S-0255
S-0380
S-0047
S-0164
S-0126
S-0223
S-0101
S-0311
S-0211
S-0445


Sub Hard B/C Ratio (without ICE)
0.072
0.071
0.07
0.069
0.068
0.067
0.066
0.065
0.064
0.063
S-0162
S-0144
S-0053
S-0084
S-0283
S-0399
S-0063
S-0503
S-0524
S-0217
S-0502
S-0210
S-0226
S-0133
S-0035
S-0255
S-0380
S-0047
S-0164
S-0126
S-0223
S-0101
S-0311
S-0211
S-0445

Total 10 Year BCA Streams by Program

Filing Program (Normal)	Benefit: Customer Outage Benefits from Failures (Normal)	Customer Outage Benefits from Other (Normal)	Reduced Restoration Capital Costs (Normal)	Reduced Restoration O&M Costs (Normal)	Avoided VM Capital Costs (Normal)	Avoided VM O&M Costs (Normal)	Equipment Life Extension (Normal)	Deferred Replacement Credit (Normal)	Cost: Program Deployment Upfront Capital (Normal)	Program Deployment Upfront O&M (Normal)	Program Deployment Ongoing Capital (Normal)	Program Deployment Ongoing O&M (Normal)	Program Deployment Removal Cost (Normal)
D1: Feeder Hardening	$ 4,016,326,192	$ -	$ 59,895,184	$ 1,091,912	$ -	$ -	$ -	$ 164,824,741	$ 1,209,831,686	$ 48,393,263	$ -	$ -	$ 266,162,974
D2: Lateral Hardening	$ 8,870,116,271	$ 2,462,000,168	$ 372,774,253	$ 5,304,407	$ 1,083,020	$ 27,368,971	$ -	$ 753,321,138	$ 1,647,352,613	$ 19,242,990	$ -	$ -	$ 148,578,644
D3: Self-Optimizing Grid (SOG)	$ -	$ 14,818,051,532	$ -	$ -	$ -	$ -	$ -	$ -	$ 232,620,871	$ 5,112,581	$ -	$ -	$ 17,894,889
D4: Underground Flood Mitigation	$ 29,221,879	$ -	$ 14,447,600	$ 176,367	$ -	$ -	$ -	$ 1,331,902	$ 10,176,126	$ -	$ -	$ -	$ 629,223
T1: Structure Hardening	$ 1,179,653,188	$ 282,788,423	$ 294,717,463	$ 5,013,649	$ -	$ -	$ 106,112,789	$ 397,956,931	$ 1,131,253,341	$ 47,365,624	$ -	$ -	$ 151,967,706
T2: Substation Flood Mitigation	$ 755,657,764	$ -	$ 5,399,450	$ -	$ -	$ -	$ -	$ 1,454,202	$ 24,700,000	$ -	$ -	$ -	$ 4,940,000
T3: Loop Radially Fed Substations	$ -	$ 166,759,807	$ -	$ -	$ -	$ -	$ -	$ 671,170	$ 54,924,000	$ -	$ -	$ -	$ 3,090,000
T4: Substation Hardening	$ 195,206,911	$ 872,531,685	$ 393,899	$ -	$ -	$ -	$ -	$ 6,711,240	$ 86,994,000	$ -	$ -	$ -	$ 17,398,800

BCA Stream	Description
Customer Outage Benefits from Failures (Normal)	Benefit stream that accrues due to reduced outage duration and frequency from fewer equipment failures during storm conditions. This reduces CMI, and is valued at the customer cost of interruption.
Customer Outage Benefits from Other (Normal)	Benefit stream that accrues due to program benefits other than reduced failures, such as connectivity. This reduces CMI, and is valued at the customer cost of interruption.
Reduced Restoration Capital Costs (Normal)	Benefit stream that accrues due to reduced equipment failures. This reduces equipment replacement capital costs in storm and blue sky conditions.
Reduced Restoration O&M Costs (Normal)	Benefit stream that accrues due to reduced equipment failures. This reduces equipment replacement O&M costs in storm and blue sky conditions.
Avoided VM Capital Costs (Normal)	Benefit stream that accrues due to reduction in VM line miles required. This reduces VM capital costs of danger and hazard tree removal.
Avoided VM O&M Costs (Normal)	Benefit stream that accrues due to reduction in VM line miles required. This reduces VM O&M costs of trimming.
Equipment Life Extension (Normal)	Benefit stream that accrues due to the addition of equipment that increases asset lifetimes, reducing the present value of capital expenditures.
Deferred Replacement Credit (Normal)	Benefit stream that accrues due to replacing existing equipment before end of life with new equipment that needs less maintenance and delays the need for replacement in the future, resulting in a cash flow benefit.
Program Deployment Upfront Capital (Normal)	Capital cost stream that accrues upfront, on installation of the equipment.
Program Deployment Upfront O&M (Normal)	O&M cost stream that accrues upfront, on installation of the equipment.
Program Deployment Ongoing Capital (Normal)	Capital cost stream that accrues periodically throughout the equipment lifetime.
Program Deployment Ongoing O&M (Normal)	O&M cost stream that accrues periodically throughout the equipment lifetime.
Program Deployment Removal Cost (Normal)	Cost stream that accrues at the end of equipment life, accounting for the cost of removal/disposal from the installation site.

IN RE: REVIEW OF 2020-2029 STORM PROTECTION PLAN PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200069-EI

REBUTTAL TESTIMONY OF

THOMAS G. FOSTER

JULY 1, 2020

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

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

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony supporting the Company's SPP on April 10, 2020.

Q. Has your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Company's rebuttal to assertions and conclusions contained in the direct testimonies of OPC's witness Schultz and Walmart's witness Chriss.

Q. Please summarize your testimony.

A. My testimony addresses certain assertions and conclusions contained in OPC Witness Schultz and Walmart Witness Chriss testimonies. I have not attempted to rebut each, and every factual error or misconception contained in these testimonies.

With regard to Witness Schultz testimony I generally focus on four topics:

- Clarification around certain requirements related to estimating benefits associated with the Statute and Rule.
- Addressing his concern that ratepayers will not receive the benefits of future reduced costs in base rates that result from SPP implementation.
- Generalizations he made regarding the adequacy of our cost estimates (this is more fully discussed in DEF Witness Oliver's rebuttal testimony).
- Address his concern that Commission approval of IOU SPPs is equivalent to a "blank check".

With regard to Walmart Witness Chriss testimony I address why DEF developed estimated rate impacts assuming collection of SPP costs on a per kWh (energy) basis.

III. OPC Witness Schultz

Q. Do you agree with OPC Witness Schultz impression on page 4 lines 1 -5 that because DEF's Storm Protection Programs are new, DEF is indicating that they only provide reduced storm costs?

A. No. DEF never states that the Programs being proposed only result in reduced storm costs. In fact, on page 4, lines 14-18, Witness Schultz shows a response provided by DEF specifically acknowledging that there will also be savings during normal operating conditions. DEF has not quantified these savings but acknowledges they exist.

Q. Why did DEF not quantify the savings during normal operating conditions?

A. DEF did not quantify these savings because they are not required to be quantified for this proceeding per the SPP Statute[1] or Rule.[2]

Q. Do you agree with Witness Schultz statement that there is a risk that ratepayers will be paying for improvements that will reduce the Company's costs in base rates, but those savings will not be passed through to the ratepayers?

A. No. The SPP statute addresses new investments to strengthen the electric utility infrastructure to withstand extreme weather conditions and improve overall service reliability. It creates a cost recovery clause for investments to accomplish this goal. It also ensures there is no double recovery for these costs by stating in paragraph (8) that "storm protection plan costs may not include costs recovered through the public utility's base rates". This clearly addresses the double recovery concern. Rule 25-6.031(6)(b) implements this statutory directive by stating "Storm Protection Plan costs

[1] Section 366.96, Fla. Stat.
[2] Rule 25-6.030, F.A.C.

recoverable through the clause shall not include costs recovered through the utility's base rates or any other cost recovery mechanism."

It is the normal process for base rate costs to change over time and this creates regulatory lag. Some costs will decrease, others will increase. The SPP Statute was not developed to address appropriate levels of costs in base rates, it was developed to facilitate investment in work that will strengthen the Transmission and Distribution systems from extreme weather to help reduce restoration times and costs. There is in fact already a way that the Commission monitors Florida IOUs to ensure no excessive recovery is occurring. The Commission requires IOUs to file monthly Earnings Surveillance reports. These reports show the IOUs earned return on equity (ROE). In a rate case the FPSC authorizes an allowed ROE for utilities. If a utility reports a ROE that is too high the parties or the Commission itself may call the Utility in for a rate case. Unlike cost recovery clauses, the normal and established process for base rates involves regulatory lag.

Q. On page 5, lines 15-22, Witness Schultz addresses the importance of cost detail for the Storm Protection Plan filing; do you agree with how he has characterized what DEF has provided and what the Rule requires?

A. No. First, he cites Rule 25-6.030(3)(d) and (e) and states they require a cost estimate for capital and operating costs along with a description of the respective projects. The way he has chosen to word this could confuse the reader. Paragraph (3)(d) is really focused on information at the program level. Paragraph (3)(e) is focused on the specific detail required to be included in the Storm Protection Plan for the first three years. Witness Schultz is not clear that there are different requirements for the first year of the Plan, which requires a "cost estimate including capital and operating expenses" as compared to years two and three which requires "estimated number and costs of projects under every specific program. . ."[3] This is important as this was a hotly debated topic during the rulemaking proceeding and the decision to not require project level detail in years beyond year one of the program was intentional based on information discussed in the drafting of the SPP Rules.

Second, he seems to be implying that DEF has presented a best wild guess of what we expect costs to be. For year one DEF has provided project level information; I would certainly not characterize this as a "best wild guess." For forward looking years, as Witness Schultz references in his testimony on page 5, lines 5-9, DEF estimated future costs based on historical averages and guidance from Finance for Indirect overheads. O&M costs were generally estimated based on historical costs as well. DEF used historical experience with costs of a similar nature and adjusted them based on any known differences to estimate future costs, this is a far cry from a "best wild guess". This topic is covered in more detail in DEF Witness Oliver's rebuttal testimony.

Q. Do you believe approval of DEF's SPP amounts to a "blank check" for initial recovery of costs as part of the SPPCRC?

[3] *Compare* Rule 25-6.030(3)(e)1.c. ("For the first year of the plan, a description of each proposed storm protection project that includes . . . A cost estimate including capital and operating expenses;"), *with* (3)(e)2. ("For the second and third years of the plan, project related information in sufficient detail, such as estimated number and costs of projects under every specific program…").

A. No. DEF has stated numerous times that the Storm Protection Plan Docket is not the appropriate venue to make specific decisions on what costs will flow through the SPPCRC. Rather, the Commission has set up a two-step process: the SPP Docket determines what Programs the Commission agrees are appropriately included as part of the Storm Protection Plan; then there is a separate cost recovery clause Docket[4] where the Commission determines what costs are appropriate for recovery through the clause pursuant to the requirements of Rule 25-6.031. SPP approval means the Commission must allow recovery of prudently incurred costs associated with the approved Plan, but the Commission and intervenors have the opportunity to challenge the prudence of the costs presented and whether they are already included in base rates or some other recovery mechanism. DEF expressed this on multiple occasions during the Rule development as shown below:

DEF's Post Rule Development Workshop Comments, July 15, 2019, Page 4, "…Once requested for inclusion in the SPP, costs associated with the new Program can be included for recovery subject to ultimate FPSC approval of the Program."

DEF's Post Rule Development Workshop Comments, July 15, 2019, Page 2, *"…(of course, to the extent cost recovery is sought through the SPP cost recovery clause, the Commission and intervenors would retain the right to review the Company's decision during the annual recovery clause docket)…"*

DEF's Post Rule Development Workshop Comments, August 27, 2019, Page 2 *"Significance of Approval of a SPP – At the workshop OPC expressed concern and uncertainty with the level of prudence that attaches upon approval of an SPP. DEF*

[4] Docket No. 20200092-EI.

believes that Commission approval of an SPP constitutes an affirmation that the Programs or activities described in the Plan are prudent to pursue. The SPP will include and thus the Commission will be asked to approve the methodology by which the utilities are selecting and prioritizing projects within the various Programs. The Commission would still be able to review and determine whether the companies were prudent in their execution of projects within a Program in the annual clause filings or when cost recovery is otherwise sought. For instance, if the cost of an approved project or Program increased ten-fold and the utility did not consider whether it was still prudent to pursue or did not evaluate lower-cost options, the Commission would be able to make a decision on whether the company has acted prudently. However, the Commission could not determine a company had acted imprudently based on no-other evidence than the company had followed its approved SPP."

IV. Walmart Witness Chriss

Q. What is your understanding of the purpose of Walmart Witness Chriss' testimony?

A. The crux of Walmart Witness Chriss' testimony is that Walmart believes the SPP costs should be allocated to the rate classes and billed on a demand basis to more accurately reflect cost causation.

Q. Do you agree with Walmart Witness Chriss' assertion on page 6 lines 1-4 that transmission and distribution costs are fixed and do not change with the amount of energy consumed by customers?

A. I agree that most of the costs associated with DEF's SPP are associated with assets that are designed to accommodate a specific capacity as opposed to a cost that specifically changes with use (like fuel costs), that is why DEF has made sure to allocate the cost to the classes on a demand basis as cost causation would dictate. However, section 366.96(1)(e) states "It is in the state's interest to strengthen electric utility infrastructure to withstand extreme weather conditions." This focus on avoiding costs due to extreme weather is important.

Q. Why do you believe this is important?

A. In Florida, IOUs have consistently been allowed to recover costs incremental to those included in base rates and associated with named storms through a storm surcharge. This provides recovery of costs associated with restoring the grid after extreme weather and is typically associated with restoring assets like poles, wires and other items that will be strengthened through the SPPs. Three recent examples are FPL's recovery of costs associated with Hurricane Matthew, Gulf's recovery of costs associated with Hurricane Michael and DEF's recovery of costs associated with Hurricane Dorian.

In Docket 20160251, Order PSC-17-0055-PCO-EI, the Commission approved FPL's request for recovery of costs associated with Hurricane Matthew. On Page 1 of Attachment A of this Order it can be seen that these costs are being billed on an energy (kWh) basis.

In Docket 20190038, Order PSC-2019-0221-PCO-EI, the Commission approved Gulf's request for recovery of costs associated with Hurricane Michael. On page 3 of Attachment A of this Order it can be seen that these costs are being billed based on an energy (kWh) basis.

In Docket 20190222, Order PSC-2020-0058-PCO-EI, the Commission approved DEF's request to implement a Storm Surcharge to recover costs associated with Hurricane Dorian. On page 6 of Attachment A it can be seen that these costs are being billed based on an energy (kWh) basis.

These Orders illustrate that the Commission has recently found it appropriate to bill customers for the types of costs the SPPs are designed to prevent on an energy basis.

Q. On page 9, lines 9-15, Walmart Witness Chriss asserts recovery of demand-related costs through an energy charge violates cost causation principles, do you agree?

A. As described above, the costs the SPP is designed to reduce have historically been collected on a per kWh basis. For this reason, I do not believe recovery of these costs through an energy charge is a violation of cost causation principles.

Q. Are there any other reasons DEF showed its estimated rate impacts with rates collected on an energy basis?

A. Yes. It was consistent both with what DEF had proposed in the Rule development workshops and with Staff's draft SPP schedules that were discussed at an informal meeting held on February 26, 2020, noticed in Docket 20200000-OT. On page SPPCRC Form 5P of Staff's draft SPP cost recovery clause schedules, the rates were shown on a per kWh basis. These schedules were discussed, and the parties given a chance to raise concerns at this meeting and no one raised a concern about how these rates were being shown.

Q. Do you believe the Commission has to require IOUs to bill on an energy basis due to the draft schedules?

A. Absolutely not. The Commission has wide discretion on this matter. I only mention it to inform the Commission and parties why DEF believes it was reasonable to propose our SPP's estimated rate impacts be collected on a per kWh basis in our SPP filing. If the Commission decides these revenues should be billed on a per kw basis for DEF's demand customers DEF will of course comply.

Q. On pages 10-12 of Walmart Witness Chriss' testimony he gives an illustrative example of the impact of allocating costs on an energy vs. demand basis to different customers within a class. Do you agree with his example?

A. The general math is a fair representation of how different methods of billing can impact different customers within a class. I do not agree with the conclusion that if a utility recovers demand-related charges through an energy-based charge it will necessarily over-collect from one customer and under-collect from another.

V. Conclusion

Q. Mr. Foster, have you responded to every contention regarding the company's proposed plan in your rebuttal?

A. No. I addressed the major points within my field of expertise that I felt required rebuttal; my decision not to refute each and every individual characterization of fact or opinion in the intervenors' testimonies should not be understood as agreement with those points. Moreover, Witness Oliver has concurrently filed rebuttal testimony directed at multiple other mischaracterizations and misconceptions contained in those testimonies.

Q. Does that conclude your testimony?

A. Yes.