STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 180

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	<u>JOINT INITIAL COMMENTS</u>
Investigation of Proposed Net Metering	)	<u>OF NC WARN, NCCSC AND</u>
Policy Changes	)	<u>SUNRISE DURHAM</u>

Pursuant to the North Carolina Utilities Commission's ("NCUC" or "Commission") *Order Requesting Comments* entered on January 10, 2022 in the above-referenced docket, as extended by the Commission's *Order Granting Extension of Time* entered on March 3, 2022, Intervenors NC WARN, North Carolina Climate Solutions Coalition ("NCCSC"), and Sunrise Movement Durham Hub ("Sunrise Durham"),[1] through undersigned counsel, hereby submit the following Joint Initial Comments:

<u>SUMMARY</u>

For numerous reasons which will be set forth herein, the Commission should reject the net energy metering ("NEM") tariffs proposed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies") in the above-referenced docket. The NEM tariffs proposed by the Companies (the "tariffs") violate applicable law, including N.C. Gen. Stat. § 62-126.4(b), and are not supported by any evidentiary basis. Instead, the proposed

---

[1] Contemporaneous with the present Initial Comments, Sunrise Durham filed a Petition to Intervene in the above-referenced docket. That petition is currently pending before the Commission.

tariffs are the result of a Memorandum of Understanding ("MOU") between the Companies and certain intervenors, yet substantial portions of that MOU—namely the Smart Saver incentives portions at issue in separate dockets—have been rejected in South Carolina and are in danger of rejection in this State. Without the Smart Saver portion of the MOU, there is even less basis for the tariffs proposed in the present docket.

NC WARN, NCCSC and Sunrise Durham retained William E. Powers ("Mr. Powers"), an engineer with over thirty-five (35) years of experience in the solar industry, to evaluate the proposed tariffs. Mr. Powers' *Report Responding to Deficiencies in the Duke Energy NEM Application* (the "Report") is attached hereto as **Attachment A**. Based upon a review of the applicable law and Mr. Powers' Report, NC WARN, NCCSC and Sunrise Durham urge the Commission to reject the Companies' proposed NEM tariffs for at least the following reasons:

- Pursuant to House Bill 589, "The Commission shall establish net metering rates **under all tariff designs** . . . ." N.C. Gen. Stat. § 62-126.4(b) (emphasis added). The Companies, however, failed to propose NEM rates "under all tariff designs." Instead, the Companies seek to require all NEM customers—even existing flat-rate NEM customers—to operate under time of use ("TOU") tariffs with critical peak pricing ("CPP") windows that are extremely disadvantageous to rooftop solar. By failing to propose tariffs "under all tariff designs," such as for flat-rate customers, the Companies' proposed NEM tariffs violate the mandate and intent of House Bill 589.

- Moreover, House Bill 589 required that the NEM "rates shall be . . . established only after an investigation of the costs and benefits of customer-sited generation." N.C. Gen. Stat. § 62-126.4(b). No such "investigation" has been conducted. Instead, the Companies purported to support the proposed tariffs with old Cost-of-Service Studies using outdated 2018 data. In addition to being outdated, the Companies' Cost-of-Service Studies concentrate upon the **costs** of rooftop solar but fail to examine in any meaningful way the **benefits**, both societal and otherwise, of rooftop solar. In no respect has there been, as required by House Bill 589, an "investigation of the costs and benefits of customer-sited generation." In furtherance of this statutory mandate, the Commission must lead a Value of Solar Study and establish NEM tariffs based upon the results of that Commission-led study.

- The Companies' proposed tariffs would disincentivize the installation of rooftop solar. Among other reasons, the Companies' own responses to data requests acknowledge that the proposed tariffs would reduce the economic value of rooftop solar for NEM customers by about thirty percent (30%). This catastrophic disincentive of rooftop solar violates the purpose and goals of both House Bill 951 and Governor Cooper's Executive Order 80.

- The Companies' tariffs would impose extravagant Minimum Monthly Bills upon NEM customers. Despite the onerous nature of the Minimum Monthly Bills, the Companies have failed to establish any cost-shift which could feasibly justify these Minimum Monthly Bills. Among other flaws with their cost-shift analysis, the Companies failed to account for the elimination of transmission and distribution investments which would result from the proliferation of rooftop solar. Because there is no basis for a supposed cost-shift, the Minimum Monthly Bills should be rejected.

- The Companies' tariffs would require NEM customers to sign up for TOU tariffs with CPP windows. The on-peak windows are not, however, based upon the Companies' historical summer peak. Instead, these windows are based upon the Companies' projection of where summer peak might be in 2026. However, the Companies have not provided any evidentiary basis for this projected shift in summer peak. Yet, the summer on-peak TOU window would cause NEM customers to pay the highest rate exactly when the sun is going down and solar systems are not generating power. Simply put, the Companies' TOU and CPP proposal is both unsupported by the evidence and uniquely detrimental to rooftop solar.

- Finally, the Companies' proposed tariffs omit several important provisions. For instance, battery storage is a fast-growing technology which is inexplicably absent from the proposed NEM tariffs. In rejecting the proposed tariffs, the Commission should order the Companies to propose new tariffs which, among other things, address NEM customers with battery storage.

For all of these reasons, among others, the Commission should reject the Companies' proposed NEM tariffs. As required by N.C. Gen. Stat. § 62-126.4(b), the Commission should lead a Value of Solar Study and, based on the results of that study, require revised NEM tariffs for all tariff designs which accurately reflect not only the costs, but also the **<u>benefits</u>**, of rooftop solar.

INDEX OF ATTACHMENTS

The following is a list of the attachments filed contemporaneously with these Initial Comments.[2] These attachments are cited in both the present Initial Comments and Mr. Powers' Report.

Attachment A: Report Responding to Deficiencies in the Duke Energy NEM Application, by Mr. Powers;

Attachment B: Deployment of NEM Solar Allows Duke Energy to Eliminate New Transmission That Would Otherwise Be Built, an Analysis by Mr. Powers;

Attachment C: Substitution of Residential NEM Solar for New Transmission Built to Serve Remote, Utility-Scale Solar in North Carolina Could Add $1,600/yr in Avoided Transmission Value to these NEM Systems, an Analysis by Mr. Powers;

Attachment D: Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study (2018);

Attachment E: The Companies' Response to the Public Staff's Data Request No. 1-3(f);

Attachment F: The Companies' Response to NC WARN's Data Request No. 2-1;

Attachment G: The Companies' Response to the Public Staff's Data Request No. 1-1;

---

[2] In response to several data requests, the Companies produced voluminous spreadsheets in native Excel format. In certain instances, those spreadsheets included intact formulas to allow the parties to make calculations. As a result, it was not possible to convert several of these Excel spreadsheets into Adobe PDF format for filing purposes. Specifically, undersigned counsel has omitted the Excel spreadsheets from the following discovery responses: **Attachment E**, the Companies' Response to the Public Staff's Data Request No. 1-3(f); **Attachment G**, the Companies' Response to the Public Staff's Data Request No. 1-1; **Attachment H**, the Companies' Response to NC WARN's Data Request No. 1-11; and **Attachment N**, the Companies' Response to the Public Staff's Data Request 1-2. Upon request, undersigned counsel will provide the native Excel spreadsheets referenced herein to Commission staff or the parties.

Attachment H:	The Companies' Response to NC WARN's Data Request No. 1-11;
Attachment I:	The Companies' Response to NC WARN's Data Request No. 5-1;
Attachment J:	The Companies' Response to NC WARN's Data Request No. 4-4;
Attachment K:	The Companies' Response to NC WARN's Data Request Nos. 1-5 & 1-10;
Attachment L:	The Companies' Response to NC WARN's Data Request Nos. 1-4 & 1-9;
Attachment M:	The Companies' Response to NC WARN's Data Request Nos. 4-1 & 4-2;
Attachment N:	The Companies' Response to the Public Staff's Data Request No. 1-2;
Attachment O:	The Companies' Response to NC WARN's Data Request No. 1-16;
Attachment P:	The Companies' Response to the Public Staff's Data Request No. 1-28;
Attachment Q:	The Companies' Response to NC WARN's Data Request No. 2-4; and
Attachment R:	The Companies' Response to NC WARN's Data Request Nos. 1-3 & 1-8.

DISCUSSION

The following constitutes a discussion of the legal and evidentiary deficiencies with the Companies' proposed NEM tariffs. Large portions of this discussion constitute summaries of Mr. Powers' Report, which Report should be consulted for additional details and supporting citations.

I. The Companies' Proposed NEM Tariffs Violate the Mandate of House Bill 589 that the Commission "Establish Net Metering Rates Under *All Tariff Designs*."

On July 27, 2017, North Carolina Governor Roy Cooper signed into law *An Act to Reform North Carolina's Approach to Integration of Renewable Electricity Generation through Amendment of Laws Related to Energy Policy and to Enact the Distributed Resources Access Act*, commonly referred to as "House Bill 589." Among other things, House Bill 589 requires the following of the Commission regarding NEM:

> The rates shall be **nondiscriminatory** and established only after an investigation of the costs and benefits of customer-sited generation. **The Commission shall establish net metering rates under all tariff designs** that ensure that the net metering retail customer pays its full fixed cost of service.

N.C. Gen. Stat. § 62-126.44(b) (emphasis added). Of particular importance for the present discussion, House Bill 589 required that the Commission establish a NEM rate for "all tariff designs." *Id.*

Presently, there are a myriad of NEM arrangements which provide customers the flexibility to select the riders which are most appropriate for the customer's needs. By way of example, there are presently NEM customers under flat-rate riders. These flat-rate NEM customers pay the same rate for electricity irrespective of the time of day that the electricity is purchased from the grid. Alternatively, there are NEM customers under TOU-based tariffs.[3]

---

[3] For example, the Companies' Joint Application discusses DEP's existing flat-rate tariff for NEM customers and DEP's TOU tariff for NEM customers. *See* Joint Application of DEC & DEP for Approval of NEM Tariffs, NCUC Docket No. E-100, Sub 180, Ex. No. 2, pdf p. 34. Notably, DEP proposes in the present docket

Unfortunately, the Companies have proposed a "one size fits all" NEM tariff. The Residential Solar Choice rider proposed by DEC in the above-referenced docket states: "Customers receiving service under this Rider **must be served** under a residential rate schedule with time of use (TOU) and critical peak pricing (CPP), specifically Schedule RSTC or RETC."[4] Similarly, the Residential Solar Choice rider proposed by DEP in the above-referenced docket states: "Customers receiving service under this Rider **must be served** under a residential rate schedule with time of use (TOU) and critical peak pricing (CPP), specifically proposed Schedule R-TOU-CPP."[5]

The Companies' Joint Application is not explicit on this point, but a review of the Companies' proposed NEM tariffs inexorably leads to the following conclusion: The Companies seek to compel all NEM customers in the State of North Carolina onto a tariff involving TOU and CPP.

In other words, the Companies would seek to eliminate an entire class of tariffs—namely, flat-rate NEM customers. This proposal violates the mandate of House Bill 589, which states: "The Commission shall establish net metering rates **under all tariff designs** . . . ." N.C. Gen. Stat. § 62-126.4(b) (emphasis added).

This violation of House Bill 589 is not a mere technicality. To the contrary, the Companies seek to force all NEM customers onto TOU and CPP tariffs which are extremely disadvantageous to rooftop solar. As discussed in more detail below,

---

that this arrangement be "closed to new residential participants on and after January 1, 2023." *Id.* at pdf p. 33.

[4] Joint Application of DEC & DEP for Approval of NEM Tariffs, NCUC Docket No. E-100, Sub 180, Ex. No. 1, pdf p. 30 (emphasis added).

[5] *Id.*, Ex. No. 2, pdf p. 41 (emphasis added).

the Companies propose an on-peak window during the summer of 6 pm to 9 pm. That window corresponds to when the sun is setting and therefore rooftop solar systems are generating hardly any power. Hence, the Companies would propose that NEM customers be forced onto TOU and CPP tariffs which will substantially reduce the value of their solar systems by forcing NEM customers to purchase power from the grid at the highest rate.[6] This "one size fits all" approach is not only inequitable and unfair, it also violates House Bill 589.

II. The Companies' Proposed NEM Tariffs Violate the Mandate of House Bill 589 That NEM Rates Be "Established Only After an Investigation of the Costs and Benefits of Customer-Sited Generation."

A. House Bill 589 Requires a Commission-led Cost-Benefit Analysis.

House Bill 589 prohibits the establishment of new NEM tariffs until after a Commission-led cost-benefit analysis is conducted regarding customer-sited generation. The applicable statute states:

> **§ 62-126.4. Commission to establish net metering rates.**
>
> . . . .
>
> (b) **The rates shall be nondiscriminatory and established only after an investigation of the costs and benefits of customer-sited generation**. The Commission shall establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service. . . .

[6] **Attachment A**, Powers' Report, pp. 15-18.

N.C. Gen. Stat. § 62-126.4(b) (second emphasis added). Self-evidently, it is mandatory that "an investigation of the costs and benefits of customer-sited generation" be conducted.

Equally important is **who** should lead the cost-benefit analysis. Every aspect of this statute requires that the Commission take lead on the establishment of new NEM tariffs. For instance, the title of the statute is, "**Commission** to establish net metering rates."[7] Subsection (a) of the statute states that "**Commission** approval" is required.[8] Subsection (b), quoted above, states that "[t]he **Commission** shall establish net metering rates."[9] In other words, the Commission is the prime mover regarding the establishment of new NEM tariffs, and the Commission should therefore lead the mandatory cost-benefit analysis. In fact, it is common for state utility commissions to lead investigations into the costs and benefits of NEM solar.[10]

Principles of statutory construction likewise require the conclusion that the "investigation of the costs and benefits of customer-sited generation"[11] be led by the Commission. For instance, "it is a fundamental principle of statutory interpretation that courts should evaluate a statute as a whole and . . . not construe an individual section in a manner that renders another provision of the same

---

[7] N.C. Gen. Stat. § 62-126.4 (emphasis added).

[8] *Id.* § 62-126.4(a) (emphasis added).

[9] *Id.* § 62-126.4(b) (emphasis added).

[10] **Attachment A**, Powers' Report, p. 23; *see also* CPUC, *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared by Energy+Environmental Economics (E3), October 2013; CPUC, *Net-Energy Metering 2.0 Lookback Study*, prepared by Verdant Associates, LLC, January 21, 2021.

[11] N.C. Gen. Stat. § 62-126.4(b).

statute meaningless."[12] Reading the statute as a whole, as we must, this "investigation," like all the other above-quoted aspects of N.C. Gen. Stat. § 62-126.4, should be conducted by the **Commission**. To conclude otherwise would be to interpret the word "investigation" in a manner which is inconsistent with the overall statute.

Another crucial tool of statutory construction involves ascertaining **legislative intent**: "The foremost task in statutory interpretation is to determine legislative intent while giving the language of the statute its natural and ordinary meaning unless the context requires otherwise."[13] Here, the evidence shows that legislators intended for the Commission to lead the cost-benefit analysis. For instance, in an article appearing in *Energy News Network*, Rep. John Szoka (R-Cumberland), who was the chief author of House Bill 589, stated the following:

> **Szoka is adamant the Commission will conduct the cost-benefit study.**
>
> "It's not up to the utility to determine whether net metering is good or bad," he said. "We know what that answer will be. We're not putting the fox in charge of the hen house here. That is not the intent."[14]

Clearly, therefore, the intent behind House Bill 589 is for the Commission, not the Companies, to lead the statutorily mandated "investigation of the costs and

---

[12] *Lunsford v. Mils*, 367 N.C. 618, 628, 766 S.E.2d 297, 304 (2014) (internal quotation marks omitted).

[13] *Carolina Power & Light Co. v. City of Asheville*, 358 N.C. 512, 518, 597 S.E.2d 717, 722 (2004) (internal quotation marks and citations omitted).

[14] Elizabeth Ouzts, *Energy News Network*, "Energy Bill could see North Carolina join national fight over net metering," July 17, 2017, https://energynews.us/2017/07/17/energy-bill-could-see-north-carolina-join-national-fight-over-net-metering/ (accessed on March 22, 2022) (emphasis added).

benefits of customer-sited generation."[15] Therefore, the Companies' Joint Application should be rejected pending a Commission-led cost-benefit analysis. As discussed in the next section of these Initial Comments, that Commission-led process should comply with the applicable standard of care for cost-benefit analyses, including the performance of a full Value of Solar Study.

B. The Applicable Standard of Care for Conducting Cost-Benefit Analyses

The applicable standard of care for conducting cost-benefit analyses of distributed energy resources, including solar, is set by the National Energy Screening Project's *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* ("NSPM-DER").[16] The NSPM-DER contains detailed rules governing the performance of cost-benefit analyses.[17] According to Mr. Powers, "[i]t is this Manual that should be utilized by the Commission to evaluate the costs and benefits of NEM solar."[18]

Among other things, the NSPM-DER recommends a detailed analysis of **customer and societal impacts** which should be examined in every cost-benefit analysis of NEM solar—*i.e.*, a Value of Solar Study is recommended by the NSPM-DER. According to the NSPM-DER, at least the following issues should be examined: low-income customer non-energy impacts, greenhouse gas emissions,

---

[15] N.C. Gen. Stat. § 62-126.4(b).
[16] **Attachment A**, Powers' Report, pp. 21-22.
[17] *Id.*
[18] *Id.* at 22.

incremental economic development and job impacts, health impacts, energy imports and energy independence, etc.[19]

Similarly, the National Renewable Energy Laboratory has stated that at least the following categories of costs and benefits are typically considered in a Value of Solar Study: (1) energy, (2) generation capacity, (3) transmission and distribution losses, (4) transmission and distribution capacity, (5) environmental costs and benefits (such as avoided emissions), (6) ancillary services (such as voltage control), and (7) other factors, such as fuel hedging.[20]

This standard of care governing cost-benefit analyses of NEM solar is further illustrated by examining analyses performed in North Carolina by independent consultants. For instance, on October 18, 2013, R. Thomas Beach ("Mr. Beach") and Patrick G. McGuire ("Mr. McGuire") of Crossborder Energy issued a report entitled *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*.[21] In that study, Mr. Beach and Mr. McGuire performed a detailed analysis of both the costs **and value** of solar. For instance, the Beach/McGuire study examined factors such as "Avoided Emissions," environmental issues, and other societal benefits of solar generation.[22]

---

[19] NSPM-DER Ch. 4.

[20] **Attachment A**, Powers' Report, p. 21; *see also* NREL, *Distributed Solar Photovoltaic Cost-Benefit Framework Study: Considerations and Resources for Oklahoma*, p. ix, August 2019, at https://www.nrel.gov/docs/fy19osti/72166.pdf (accessed on March 22, 2022).

[21] R. Thomas Beach & Patrick G. McGuire, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 18, 2013, at https://energync.org/wp-content/uploads/2017/03/Benefits_Costs_Solar_Generation-for_Electric_Ratepayers_NC.pdf (accessed on March 22, 2022).

[22] *E.g.*, *id.* at 1 & 3.

Notably, Mr. Beach was the consultant hired by several of the signors to the MOU during the NEM litigation in South Carolina.[23] As discussed in more detail below, in the South Carolina NEM litigation involving Dominion Energy South Carolina, Mr. Beach, following a cost-benefit analysis similar to that which he conducted in North Carolina, concluded that "there is not presently a cost shift from solar customers to non-participating ratepayers," and "there are significant, quantifiable societal benefits from distributed solar, including public health benefits from reduced air pollution and from mitigating the damages from carbon emissions."[24]

These reports by Mr. Beach illustrate that the standard of care for cost-benefit analyses requires the consideration of the costs and benefits, including societal benefits, of solar. As discussed in the next section, the Companies failed to comply with this standard of care.

C. The Companies Have Failed to Conduct a Cost-Benefit Analysis Consistent with the Applicable Standard of Care and as Required by House Bill 589.

According to Mr. Powers' Report and the evidentiary record, the Companies failed to conduct a Value of Solar Study as required by the applicable standard of care.[25] Therefore, the Companies failed to fulfill the mandate of House Bill 589 that "an investigation of the costs and benefits of customer-sited generation" be conducted.[26]

---

[23] *See* PSCSC, Docket No. 2019-182-E, *Rebuttal Testimony of R. Thomas Beach*, October 29, 2020.

[24] *Id.* at 2.

[25] **Attachment A**, Powers' Report, pp. 21-23.

[26] N.C. Gen. Stat. § 62-126.4(b).

In the above-captioned docket, NC WARN served the following data request upon the Companies: "Provide any value-of-solar studies completed by the Companies in the last ten years for distributed (rooftop) solar."[27] In response, the Companies stated: "The Company has calculated the value of solar through both embedded and marginal lenses. These studies are provided through question 2 in the Public Staff's Data Request sent December 22, 2021."[28]

The Companies' answer was non-responsive. In fact, the studies referenced by the Companies evaluated embedded **costs** and marginal **costs**—**not the value or benefits** of NEM solar. The Companies' response to "question 2 in the Public Staff's Data Request" described these studies exclusively in terms of **costs**: "Attached, please see the final versions of the embedded and marginal **cost** studies and supporting modeling, which are updated and vary slightly from those **cost** studies shared previously in an informal data request."[29, 30] At no place within the Companies' response did they reference how these studies analyzed the **benefits** of NEM solar. The reason is simple: the Companies failed to meaningfully analyze the benefits of NEM solar.

[27] **Attachment O**, the Companies' Response to NC WARN's Data Request No. 1-16.

[28] *Id.*

[29] **Attachment N**, the Companies Response to the Public Staff's Data Request No. 1-2 (emphasis added).

[30] The studies produced by the Companies in response to the Public Staff's Data Request No. 1-2 (**Attachment N**) were produced as part of a Zip file which included multiple native Excel format spreadsheets. Due to the nature of these files, it was not possible to convert the same to Adobe PDF for filing purposes. Upon request, undersigned counsel will provide the native files to Commission staff and/or the parties.

Even if the Companies' studies briefly grapple with the benefits of NEM solar (which is denied), it is incontestable that the Companies' studies failed to analyze, or even mention, the societal value of solar, such as environmental impacts. As described above, these social-value components of a cost-benefit analysis are mandatory under the applicable standard of care. Therefore, even the purported studies cited by the Companies are woefully deficient.

Indeed, the Public Staff served data requests in this docket which cast doubt upon the supposed notion that the Companies conducted a Value of Solar Study. For instance, the Public Staff served the following data request upon the Companies: "Please explain why the Companies declined to perform a Value of Solar Study to assist in developing the proposed Rider RSC."[31] In response, the Companies went into extensive detail about their examination of the **cost** of NEM solar. For instance, the Companies explained that "Duke Energy provided embedded and marginal cost analyses."[32] However, the Companies were able to offer only a single weak example of the evaluation of the **value** of NEM solar: "While the Companies did not retain a third party to perform a Value of Solar Study (VOSS), as part of the Comprehensive Rate Review stakeholder process, the Companies did perform a VOSS, which was shared with stakeholders."[33] However, as explained below, the Comprehensive Rate Review stakeholder process is entirely inadequate as a Value of Solar Study.

---

[31] **Attachment P**, the Companies' Response to the Public Staff's Data Request No. 1-28.

[32] *Id.*

[33] *Id.*

The Companies' analysis is flawed for yet more reasons. For instance, the Companies' cost of service studies were based on data from test-year 2018.[34] This data is ancient, and the Companies' studies are therefore unreliable.

By the Companies' own admission, they have not hired an independent third party to perform a Value of Solar Study.[35] Instead, the Companies ask both stakeholders and this Commission to "take their word for it" that an accurate analysis (based upon outdated 2018 data) has been conducted internally by the Companies of the costs and benefits of solar. But their word, by itself, is insufficient to satisfy the requirement of House Bill 589 that "an **<u>investigation</u>** of the costs **<u>and benefits</u>** of customer-sited generation" be conducted.[36] In violation of the plain language and intent behind House Bill 589, the Companies are the fox guarding the hen house.[37]

D. <u>The NEM Portion of the Rate Design Stakeholder Process Cannot Satisfy the Requirement of a Value of Solar Study.</u>

The Companies will argue that the requirement of a Value of Solar Study was satisfied by the NEM portion of the Rate Design Stakeholder Process. As

---

[34] **Attachment N**, the Companies' Response to the Public Staff's Data Request No. 1-2.

[35] **Attachment P**, the Companies' Response to the Public Staff's Data Request No. 1-28.

[36] N.C. Gen. Stat. § 62-126.4(b) (emphasis added).

[37] Elizabeth Ouzts, *Energy News Network*, "Energy Bill could see North Carolina join national fight over net metering," July 17, 2017, https://energynews.us/2017/07/17/energy-bill-could-see-north-carolina-join-national-fight-over-net-metering/ (accessed on March 22, 2022) (quoting Rep. John Szoka (R-Cumberland), the chief author of House Bill 589, as follows: "We're not putting the fox in charge of the hen house here. That is not the intent.").

described in Mr. Powers' Report, this argument should be rejected as clearly erroneous.[38]

In fact, the NEM portion of the Rate Design Stakeholder Process minimized discussion and instead sought to achieve approval for the Companies' NEM tariffs. The numerous defects with the NEM portion of the Rate Design Stakeholder Process were discussed in detail within NC WARN and Appalachian Voices' *Response to Duke Energy's Rate Design Study Quarterly Status Report for Third Quarter 2021*.[39] By way of example but not limitation, the NEM portion of the Rate Design Stakeholder Process was defective for the following reasons:

- The NEM portion of the Rate Design Stakeholder Process was inexplicably, and without the consultation of stakeholders, placed on a "fast track" process.[40] Pursuant to this "fast track" process, the NEM topic was the subject of discussion over a mere six (6) weeks. Various stakeholders expressed repeated objections to the inclusion of NEM on a "fast track" process. The placement of NEM on a "fast track" process is indefensible given that there is no deadline for the implementation of revised NEM tariffs,[41] and the concept of NEM presents extremely complicated factual issues regarding cost-shifts, TOU and CPP, and

[38] **Attachment A**, Powers' Report, pp. 22-23.

[39] *NC WARN and Appalachian Voices' Response to Duke Energy's Rate Design Study Quarterly Status Report for Third Quarter, 2021*NCUC Docket Nos. E-7, Sub 1214 & E-2, Sub 1219, November 15, 2021.

[40] *Id.* at 4-6.

[41] The applicable statute, N.C. Gen. Stat. § 62-126.4(c), states that retail customers may "continue net metering under the net metering rate in effect at the time of interconnection until January 1, 2027," but no provision of Chapter 62 requires that revised NEM tariffs be approved before January 1, 2027.

other complex issues. NEM is not susceptible to meaningful analysis on a "fast track" basis.

- The entire structure of the NEM portion of the Rate Design Stakeholder Process was designed to promote adoption of a South Carolina-based model. As the Commission is aware, on or about May 19, 2021, the Public Service Commission of South Carolina ("PSCSC") approved a Memorandum of Understanding ("SC MOU") concerning NEM tariffs between the Companies and several prominent participants of the Rate Design Stakeholder Process.[42] During the initial Fast Track Working Group Kick-Off meeting held on July 6, 2021, the third-party facilitator, ICF, made a presentation which forecast that the entire NEM discussion would focus upon the model espoused in the SC MOU. A copy of the only slide on NEM presented during this Kick-Off meeting is as follows:

Subgroup B: NEM Designs, NC/SC Differences

- In-scope:
  - Review of SC Settlement
    - Mandatory TOU-CPP Rate design
    - Netting policy
    - Non-bypassable rider collection
    - DSM/EE incentives
    - Grandfathering policy
    - Non-residential NEM policies
  - NC changes
    - TOU period changes (as discussed in Subgroup A)
    - GAF methodology

[42] PSCSC Docket Nos. 2020-264-E & 2020-265-E.

Obviously, the Companies and ICF considered that the only matters "In-scope" for NEM during the Rate Design Stakeholder Process were the SC MOU, and any modest tweaks which might be made in North Carolina.[43]

- The NEM portion of the Rate Design Stakeholder Process was plagued by the untimely, half-hearted distribution of material information. By way of example, the slide-deck used during the meeting on July 22, 2021, which was shared at 3:47 pm on the afternoon before the meeting, contained substantive information designed by the Companies to encourage adoption of their preferred TOU windows applicable to the NEM tariffs. This late disclosure made it impossible to prepare for discussions to be held the very next day (*i.e.*, July 22, 2021). NC WARN and Appalachian Voices' *Response to Duke Energy's Rate Design Study Quarterly Status Report for Third Quarter 2021* provided a detailed chronology which proves that agendas, slide-decks and other substantive information were provided in a manner which eliminated the possibility of meaningful discussion.[44]

In addition to the above procedural issues, the NEM portion of the Rate Design Stakeholder Process cannot satisfy the definition of an "investigation" as required by House Bill 589.[45] An "investigation" implies a thorough analysis of the data by subject-matter experts. Instead, the NEM portion of the Rate Design

---

[43] *NC WARN and Appalachian Voices' Response to Duke Energy's Rate Design Study Quarterly Status Report for Third Quarter, 2021*NCUC Docket Nos. E-7, Sub 1214 & E-2, Sub 1219, pp. 6-8, November 15, 2021.

[44] *Id.* at 8-13.

[45] N.C. Gen. Stat. § 62-126.4(b) ("The rates shall be nondiscriminatory and **established only after an investigation** of the costs and benefits of customer-sited generation." (emphasis added)).

Stakeholder Process occurred over a short six (6) weeks, involved very limited access to data, and participants had no right to conduct discovery.

In the Joint Application, the Companies stated: "the Companies surveyed several organizations participating in these workshops, and that survey revealed that 80% of those organizations were either 'supportive' or 'very supportive' of the overall NEM proposal offered by the Companies."[46] In response to NC WARN's data requests, the Companies provided a spreadsheet summarizing the said survey conducted during the NEM portion of the Rate Design Stakeholder Process.[47] The Companies' representation of the results of this survey is simply not accurate.

Eighteen (18) participants responded to the survey.[48] Of those eighteen (18) respondents, at least six (6) were signors to the NC MOU and/or the SC MOU, or law firms representing the said signors, namely: SACE, Coastal Conservation League, Southern Environmental Law Center, NC Sustainable Energy Association, Vote Solar, and Sunrun.[49] Obviously the inclusion of those survey respondents who were already committed to the SC MOU—and were therefore already committed to a similar model in North Carolina[50]—injected substantial bias into the survey results.

---

[46] Joint Application, p. 11.

[47] **Attachment Q**, the Companies' Response to NC WARN's Data Request No. 2-4.

[48] *Id.*

[49] *Id.*

[50] On page 1, the SC MOU states: "The Parties intend to work collaboratively to advance the terms of this [SC] MOU, including engaging other stakeholders on this matter in advance of filing the Solar Choice Tariffs in South Carolina and to obtain the PSCSC and the North Carolina Utilities Commission

In fact, a review of the survey results reveals that only four (4) respondents who did not sign the preexisting SC MOU were supportive of the proposed NEM tariffs: CIGFUR ("Somewhat supportive with moderate changes"), Synapse ("Supportive with minor changes"), an unnamed individual ("Somewhat supportive with moderate changes"), and Alliance for Transportation Electrification ("Very supportive").[51] Accordingly, the Companies' argument that the Rate Design Stakeholder Process generated support for the proposed NEM tariffs is factually incorrect. This lack of support is especially troublesome given that, as discussed above, the entire stakeholder process was designed by the Companies to avoid discussion and data-sharing in favor of promoting the supposed merits of the proposed NEM tariffs.

For all of these reasons, among others, the Rate Design Stakeholder Process cannot satisfy the mandate of House Bill 589 that "an investigation of the costs and benefits of customer-sited generation" be conducted.[52]

III. <u>The Companies' Proposed NEM Tariffs Would Reduce the Economic Value of Rooftop Solar Systems by Approximately Thirty Percent (30%), Thereby Disincentivizing Rooftop Solar and Violating North Carolina's Public Policy.</u>

The Companies' responses to data requests in the above-referenced docket prove that the proposed NEM tariffs would drastically reduce the economic

("NCUC") approvals necessary to effectuate this [SC] MOU. The Parties ultimately desire to avoid a contentious adversarial proceeding before the PSCSC or the NCUC by collaborating to implement the Solar Choice Tariffs within the spirit of Act 62 and North Carolina law."

[51] **Attachment Q**, the Companies' Response to NC WARN's Data Request No. 2-4.

[52] N.C. Gen. Stat. § 62-126.4(b).

value of rooftop solar systems. According to Mr. Powers, the evidence shows "a 30 percent reduction in value for these NEM systems under the proposed tariff and without the incentive payment."[53]

In his report, Mr. Powers describes how "the Year 1 NEM savings under the DEC residential RS tariff for an 8.37 kW solar array would decline from $75.76 per month to $53.59 per month."[54] This reduction in savings amounts to twenty-nine percent (29%) for DEC's NEM customers under the RS tariff.[55] Similarly, according to Mr. Powers' analysis, "[t]he Year 1 NEM savings under the DEC residential RE tariff for an 9.95 kW solar array would decline from $85.42 per month to $59.03 per month," which is "a 31 percent decline in NEM savings" for DEC's NEM customers under the RE tariff.[56]

Unfortunately, this significant savings reduction is similar for DEP's NEM customers. According to Mr. Powers, "[t]he Year 1 NEM savings under the DEP residential RES tariff for an 9.09 kW solar array would decline from $97.61 per month to $68.44 per month."[57] This reduction in savings amounts to thirty percent (30%) for DEP's NEM customers.[58]

In short, the Companies' proposed NEM tariffs would drastically reduce the value of solar systems to NEM customers. This disincentivization of rooftop solar is inconsistent with the public policy of North Carolina.

---

[53] **Attachment A**, Mr. Powers' Report, p. 10.
[54] *Id.*
[55] *Id.*
[56] *Id.*
[57] *Id.*
[58] *Id.*

For example, in Executive Order No. 80, Governor Cooper directed the development of a state Clean Energy Plan.[59] The resulting Clean Energy Plan sets goals to reduce electric utilities' greenhouse gas emissions by 70% below 2005 levels by 2030 and achieve carbon neutrality by 2050.[60] Discouraging the installation of rooftop solar, as the Companies propose to do, is completely inapposite with Executive Order No. 80 and the Clean Energy Plan.

Relatedly, House Bill 951 was signed into law by Governor Cooper on October 13, 2021. Among other things, House Bill 951 "requires implementation of a carbon emissions reduction plan for the State's public utilities,"[61] including the Companies. The Companies' discouragement of rooftop solar undermines this goal of reducing carbon emissions.

This is the worst possible time to discourage rooftop solar and undermine the above-cited carbon-reduction goals. In a new report issued on March 28, 2022, the Environmental Defense Fund ("EDF") analyzed emissions data and concluded "that North Carolina will fall short of its 2025 and 2030 climate targets without additional policies to curb emissions."[62] The new report by EDF illustrates the

---

[59] *Executive Order No. 80*, October 29, 2018, at https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf (accessed on March 22, 2022).

[60] *North Carolina Clean Energy Plan*, October 2019, at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf (accessed on March 22, 2022).

[61] Joint Application, p. 7.

[62] *New Report: North Carolina Off Track for Reaching its Own Climate Goals*, Environmental Defense Fund, March 28, 2022, at https://www.edf.org/media/new-report-north-carolina-track-reaching-its-own-climate-goals (accessed on March 29, 2022).

urgent need for the Commission and the Companies to foster—not undermine—rooftop solar. Otherwise, it will become even more difficult to meet the carbon-reduction goals cited above.

Given North Carolina public policy designed to curb the ongoing climate crisis, rooftop solar is more important than ever. Yet the Companies' proposed NEM tariffs will exacerbate the climate crisis by reducing the savings from rooftop solar by about thirty percent (30%) and thereby discouraging the Companies' customers from installing rooftop solar.

IV. The Companies' NEM Tariffs Propose an Extravagant MMB Which Is Devoid of Any Evidentiary Support.

A. The MMB Proposed by the Companies Is Extravagant.

In the Joint Application, DEC proposed a Minimum Monthly Bill ("MMB") for NEM customers of $22 per month, and DEP proposed a MMB for NEM customers of $28 per month.[63] This MMB is unnecessarily extravagant and should therefore be treated with great skepticism.

According to the MOU in NC, the purpose of the MMB is "to ensure recovery of customer and distribution costs from residential NEM customers."[64] However, as described by Mr. Powers, the Companies' "residential NEM solar customers already pay a BFC [*i.e.*, Basic Facilities Charge] of $14 per month (except for customers on two DEP TOU rate schedules who pay $16.85 per month)."[65] The purpose of the BFC is to "cover[] fixed costs of providing service to your location

[63] Joint Application, p. 14.
[64] Joint Application, Exhibit A to the MOU.
[65] **Attachment A**, Powers' Report, pp. 6-7.

as well as maintaining customer records, billing and other transactions affecting your account."[66] Hence, there is tremendous redundancy between the BFC and the MMB. Moreover, according to Mr. Powers, "[t]he BFC range is presently at the high end of BFC charges paid by utility customers around the country."[67] Accordingly, the addition of a MMB further exacerbates the Companies' already extravagant fixed charges imposed upon NEM customers.

The Companies will argue that the onerous nature of the MMB is mitigated by certain offsets. However, these offsets are largely illusory. In response to the Public Staff's data requests, the Companies provided a spreadsheet, with formulas intact, which can be used to estimate a customer's monthly bill under the proposed NEM tariffs.[68] According to the Public Staff, "[t]he purpose of this request is to better understand how the non-by-passable charges, grid access fee (GAF), and monthly minimum bill (MMB) interact."[69]

The spreadsheet provided by the Companies in response to the Public Staff's data request[70] demonstrates the illusory nature of the MMB offsets. Following an analysis of this spreadsheet, Mr. Powers concluded, "In the DEC example provided in the NEM bill calculator, only $9.92 of the NEM customer's

---

[66] *Id.* at 7.
[67] *Id.*
[68] **Attachment G**, the Companies' Response to Public Staff Data Request No. 1-1.
[69] *Id.*
[70] The referenced spreadsheet, which was produced in native Excel format, obviously cannot be used to calculate monthly bills when filed in Adobe PDF format. Accordingly, **Attachment G** omits the actual spreadsheet. Upon request, undersigned counsel will provide the native Excel version of the spreadsheet to Commission staff and/or the parties.

$58.82 of accrued monthly volumetric energy charges (for 405 kWh of purchased electricity) count toward offsetting the MMB."[71]

This extremely modest offset occurs "because Duke Energy has determined that only a relatively small portion of the volumetric energy charge is usable to offset the MMB," and "[e]nergy production charges and production and transmission demand charges, which together comprise about two-thirds of the DEC volumetric energy charge, are not eligible to offset the MMB."[72] Therefore, NEM customers "will need to accrue substantial monthly volumetric charges ($58.82/month [in the DEC example]) to offset relatively small MMB 'gap' charges ($9.92/month [in the DEC example])."[73] According to Mr. Powers, similar results follow from an examination of DEP's proposed MMB.[74]

Therefore, the MMB is both redundant of the BFC and is overly extravagant because, among other reasons, the offset feature is illusory.

B. There Is No Evidentiary Support for the MMB, Partly Because the Companies' Cost-Shift Analysis Contains Several Flaws.

To support the MMB, the Companies claim that there is a cost-shift from NEM residential customers to non-NEM residential customers. However, the entire concept of a cost-shift is unsupported by the evidence, party because the Companies' cost-shift analysis contains several analytical flaws. Therefore, the MMB proposed in the Companies' NEM tariffs should be rejected.

[71] **Attachment A**, Powers' Report, p. 7.
[72] *Id.*
[73] *Id.*
[74] *Id.*

First, it is important to place the alleged cost-shift into context. The Companies allege a cost-shift from NEM residential customers to non-NEM residential customers of approximately $10 million at the end of 2020.[75] However, according to Mr. Powers, this is only "1/100th the approximately $1 billion per year that residential DEC and DEP customers pay in excess of what the DEC and DEP full cost-of-service ('COS') studies indicate they should be paying."[76] In other words, the Companies' residential customers are already "paying 25 percent more than their full COS."[77] Hence, the amount of the alleged NEM cost shift is insignificant compared with the additional costs already being borne by the Companies' residential customers relative to other customer classes. If the goal is to rectify cost shifts, it is extremely unfair to begin with residential NEM customers.

In fact, the Companies' cost-shift analysis is flawed because of this emphasis upon residential NEM customers to the exclusion of an examination of the cost-shifts caused by other customer classes. Indeed, the Joint Application "focuses exclusively on addressing the alleged cost-shift between two subsets of residential customers," namely NEM residential customers and non-NEM residential customers.[78] By exclusively analyzing this single category of cost shift, the Joint Application fails "to assess the alleged cost-shift between NEM customers as a whole (both residential NEM and non-residential NEM customers), and non-

---

[75] *Id.* at 4.
[76] *Id.*
[77] *Id.*
[78] *Id.* at 5.

NEM residential and non-residential customers."[79] Therefore, the Companies have presented a flawed, unreliable cost-shift analysis.

According to Mr. Powers, had the Companies meaningfully analyzed the cost-shift between all NEM and all non-NEM customers—as opposed to just residential customers—the results would likely have revealed that the true cost-shift is in favor of non-NEM customers.[80] In support of this conclusion, Mr. Powers relied upon a thorough cost-shift analysis conducted in the State of California, which found that, collectively, "the NEM residential and non-residential customers were paying 103 percent of their full COS."[81] In other words, "the NEM customers were collectively paying more than their full COS—$12 million per year more—providing net cost benefits to non-NEM customers."[82] The Companies' flawed approach to the cost-shift problem, which meaningfully analyzed only residential customers, failed to consider these issues. Until these flaws are rectified, the Companies' cost-shift conclusions are unreliable.

The Companies' cost-shift analysis is flawed for yet further reasons. For instance, the installation of "NEM solar can reduce or eliminate expansion of the transmission and distribution ('T&D') system that would otherwise be necessary to accommodate load growth and grid congestion at times of peak demand."[83] Yet

[79] *Id.*
[80] *Id.*
[81] *Id.* at 6.
[82] *Id.*
[83] *Id.* at 8.

the Companies' "avoided T&D calculation assumes incorrectly that NEM solar is only deferring T&D expansion that will inevitably occur, and not eliminating it."[84]

Indeed, Mr. Powers' analysis establishes that the value of NEM for eliminating capital investment in T&D expansion is substantially greater than the avoided T&D value of NEM that the Companies assume in their cost-shift analysis. Drawing upon analyses in the ongoing California NEM litigation, Mr. Powers calculated that "the avoided cost of high voltage transmission alone would be about $935 per year per typical 9 kW" system.[85] This is substantially greater than the NEM avoided T&D value assumed by the Companies ($196-$247/year for DEC and $127/year for DEP).[86]

In his report, Mr. Powers identified yet another savings caused by NEM solar which the Companies failed to correctly analyze. As described by Mr. Powers, a significant "potential savings is achieved by NEM solar, as much as $1,600 per year per 9 kW NEM system . . . when NEM solar substitutes for remote utility-scale solar that is reliant on new or upgraded transmission to enable it to be delivered to demand centers."[87] Combined, the Companies "are investing about $1 billion per year on new reliability and expansion-related transmission and distribution projects."[88] According to Mr. Powers' analysis, "[t]he substitution of NEM solar in the demand centers of North Carolina where DEC and DEP customers are concentrated would potentially eliminate the need for transmission

---

[84] *Id.*
[85] *Id.*
[86] *Id.*
[87] *Id.* at 9.
[88] *Id.*

reinforcement between these demand centers and rural southeastern North Carolina utility-scale solar farms, and potentially for expansion-related distribution projects."[89]

Had the Companies not committed these material flaws, the results of their cost-shift analysis would have been considerably different. An instructive example involves the recent NEM litigation in South Carolina involving Dominion Energy South Carolina ("DESC"). During that said litigation, several of the signors to the MOU in NC sponsored testimony by Mr. Beach which stated as follows:

> As a result, there is not presently a cost shift from solar customers to non-participating ratepayers . . . . Finally, there are significant, quantifiable societal benefits from distributed solar, including public health benefits from reduced air pollution and from mitigating the damages from carbon emissions.[90]

Partially in reliance upon this testimony, the PSCSC rejected the tariff proposed by DESC and concluded that the utility's cost-shift analysis was flawed: "DESC's methodology for calculating cost shift, as discussed in the testimony of Witness Everett, is unreasonable because its methodology does not consider all of the benefits of customer-generated solar."[91] In fact, the PSCSC concluded that there was no cost shift at all: "The portions of the Joint Solar Choice Proposal approved in this Order do not cause a significant potential cost-shift when

[89] *Id.*

[90] PSCSC, Docket No. 2019-182-E, *Rebuttal Testimony of R. Thomas Beach*, October 29, 2020, at p. 2.

[91] PSCSC, Docket No. 2020-229-E, Order No. 2021-391, Order Establishing Solar Choice Tariff for Customers Beginning June 1, 2021, pp. 23-24.

considering the cost to serve residential solar customer-generators under DESC's existing embedded cost of service methodology."[92]

As described above, and in Mr. Powers' report, the Companies' cost-shift analysis is riddled with flaws. The Companies have failed to establish that there is a cost-shift from NEM residential customers to non-NEM residential customers. Indeed, the example of DESC in South Carolina shows that a reasonable analysis will reveal that there is no cost shift. Therefore, there is no evidentiary basis for the MMB, and the Commission should reject the MMB being proposed by the Companies.

V. The Companies' Proposed Tariffs Would Force NEM Customers onto TOU and CPP Arrangements Which Are Not Supported by Evidence and Disadvantage Rooftop Solar.

As discussed *supra*, the Companies seek to force all NEM customers onto TOU and CPP arrangements. The Joint Application would subject all NEM customers to tariffs involving an off-peak rate, discount rate (1am-6am summer; 1am-3am & 11am-4pm winter), a high on-peak pricing window of 6pm-9pm in summer and 6am-9am winter, and CPP for high-demand dates.[93]

During on-peak and CPP periods, NEM customers would pay higher rates to purchase power from the grid. This would be especially problematic for NEM

[92] *Id.* at 28.

[93] For details of these TOU and CPP windows, see Duke Energy Carolinas, LLC's Compliance Tariffs for Dynamic Rate Pilots and Advanced TOU Rates, Docket Nos. E-7, Sub 1146 and E-7, Sub 1253, Sept. 1, 2021, pdf pp. 54-55 and 57-58, at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fa7fce6d-a74a-4dfd-93d4-7982bd0634e1, and Duke Energy Progress, LLC's Compliance Tariffs, Docket Nos. E-2, Subs 1219 and 1280, Jan. 18, 2022, pdf pp. 8-9, at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=b7bddd24-0df1-496c-9e39-cdc50803158c.

customers during the summer window (6pm-9pm). Obviously, the sun is on its way down by 6 pm, and much less solar energy will be generated after 6 pm. Therefore, as discussed by Mr. Powers, the proposed TOU windows are extremely disadvantageous to solar customers, who would be forced to pay the highest rate for power exactly when their solar systems stop generating power.[94]

Perversely, the summer TOU on-peak window is also unsupported by the evidence. "In 2020, the DEC summer month peak hour in July, August, and September occurred between 4 pm – 5 pm. The 2020 DEP summer month peak hour occurred in the 4 pm hour."[95] In other words, the Companies' TOU windows are based upon where the Companies think that peak might eventually be—not where peak has historically been. To be specific, the Companies' TOU windows are based upon where the Companies believe that peak will be in 2026.[96]

NC WARN repeatedly requested that the Companies provide evidentiary support for these summer on-peak TOU windows. In response to NC WARN's data requests, the Companies declined to provide any such information supporting the alleged shift in summer peak, and the Companies repeatedly dodged NC WARN's data requests regarding the summer peak.[97]

For instance, NC WARN's Data Request No. 1-3 stated: "To the extent that DEC is proposing time of use windows based upon its prediction that peak will shift substantially by 2026, please provide (a) all data supporting this modeled shift, and

---

[94] **Attachment A**, Powers' Report, pp. 15-18.
[95] *Id.* at 16.
[96] *Id.* at 15-16.
[97] **Attachment M**, the Companies' Responses to NC WARN's Data Request Nos. 4-1 & 4-2.

(b) the model used to predict the shift, and (c) all modeling input parameters, and (d) the basis for any assumptions used in defining the numeric value of the parameters."[98] The Companies provided a non-responsive, non-substantive answer: "DEC is not proposing new time-of-use (TOU) windows in this docket. The filing in this docket only requires NEM customers to be served under Schedule RS-TC and RE-TC, but it does not establish new TOU windows."[99] Clearly, this information did not fairly address NC WARN's data request. Unfortunately, DEP provided a nearly identical response to a similar request.[100]

In an effort to obtain this crucial information about the evidentiary basis for the summer on-peak window which the Companies seek to impose upon all NEM customers, NC WARN served another round of data requests designed to address the Companies' prior non-responsive answers.[101] Yet again, the Companies failed to provide responsive information. DEC provided a completely non-substantive response, simply stating that "the Companies are not proposing new time-of-use windows in this docket."[102] DEP also indicated that "the Companies are not proposing new time-of-use windows," and DEP added that these TOU windows were studied during the "Comprehensive Rate Design Study."[103] As described *supra*, that Rate Design Stakeholder Process was deeply flawed and one-sided,

---

[98] **Attachment R**, the Companies' Response to NC WARN's Data Request No. 1-3.

[99] *Id.*

[100] **Attachment R**, the Companies' Response to NC WARN's Data Request No. 1-8.

[101] **Attachment M**, the Companies' Responses to NC WARN's Data Request Nos. 4-1 & 4-2.

[102] *Id.* at No. 4-1.

[103] *Id.* at No. 4-2.

and the Companies' survey of participants in the stakeholder process was non-scientific and biased.[104]

As set forth above, NC WARN has repeatedly requested that the Companies provide evidence in the present docket regarding the summer on-peak window which the Companies seek to impose upon every NEM customer. The Companies have failed to do so. Hence, there is simply no evidentiary basis for the TOU windows proposed in the Companies' NEM tariffs.

As discussed by Mr. Powers, the "previous DEC (pilot) *Residential Service Time-of-Use – Critical Peak Pricing* tariff, implemented in 2019, had a summer peak window of 2 pm – 8 pm, and a winter peak period windows of 6 am – 10 am and 6 pm – 9 pm."[105] Naturally, the previous summer peak window (2pm-8pm) "would substantially increase the revenue generated by a solar-only rooftop system on a TOU tariff."[106] In contrast to the 6pm-9pm window which the Companies seek to force upon all NEM customers, the prior summer peak window (2pm-8pm) was based upon the Time-of-Use and Seasonable Pricing Study issued in February 2018.[107] There is no comparable study—in fact, no evidence whatsoever—supporting the on-peak summer window of 6pm-9pm which the Companies seek to impose upon all NEM customers in the present docket.

---

[104] *See* Section II.D of these Initial Comments.

[105] **Attachment A**, Powers' Report, p. 16.

[106] *Id.*

[107] *Id.* at 17; *see also* Duke Energy Carolinas, LLC, Response to April 22, 2019 Order Requiring Additional Information, NCUC Docket No. E-7, Sub 1146, May 23, 2019, Attachment 1 - Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study, February 2018.

Given that the proposed summer on-peak TOU window is extremely disadvantageous to solar customers, the lack of supporting evidence for that window justifies rejecting the Companies' proposed tariffs.

VI. The Companies' Proposed NEM Tariffs Omit Several Material Issues.

Several important issues are conspicuously absent from the Companies' proposed NEM tariffs. For instance, "[b]attery storage is rapidly becoming a standard element of NEM solar systems."[108] Given that the Companies propose to require NEM customers to contract for TOU and CPP windows, it is especially important that customers be allowed to avoid high on-peak pricing through battery storage technology. Yet the proposed NEM tariffs are silent on battery storage.

Moreover, the proposed NEM tariffs fail to include provisions for low- and fixed-income customers. According to Mr. Powers, "[a]n equitable, well-funded on-bill financing and/or on-bill repayment program, tied to the electric meter ('tariffed') and not to the customer, would potentially lessen the" above-described barriers presented by the Joint Application.[109]

VII. The MOU Should Be Given No Weight by the Commission.

As the Commission is aware, the Companies' proposed tariffs are based upon a MOU among certain parties to the above-captioned docket. Significantly, that MOU is nonunanimous—*i.e.*, numerous prominent parties to the present docket would not agree to the MOU.

---

[108] **Attachment A**, Powers' Report, p. 20.
[109] *Id.* at 20-21.

In *State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n*,[110] the North Carolina Supreme Court, in the context of a general rate case, emphasized the skepticism which the Commission must exercise when considering a nonunanimous settlement agreement. The Supreme Court stated that "Chapter 62 contemplates a full and fair examination of evidence put forth by *all* of the parties," and "[t]o allow the Commission to dispose of a contested rate case by stipulation of less than all certified parties would effectively absolve the Commission of its statutory and due process obligations to afford all parties a fair hearing."[111] The Supreme Court proceeded to describe several problems with nonunanimous settlement agreements:

> The adoption of a non-unanimous stipulation raises several due-process concerns. The most obvious is the possibility that opposing parties may be denied an opportunity to present evidence against acceptance of the stipulation. **A more subtle problem is the possibility of an unintentional shift of the burden of proof from the utility to the opponents of the stipulation. There is a danger that when presented with a ready-made solution, the Commission might unconsciously require that the opponents refute the agreement**, rather than require the utility to prove affirmatively that the proposed rates are just and reasonable.[112]

Therefore, the Supreme Court held that, notwithstanding the presence of a nonunanimous settlement agreement, the Commission nonetheless must "set[] forth its reasoning and make[] 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all

---

[110] 348 N.C. 452, 462-67, 500 S.E.2d 693, 701-03 (1998).
[111] *Id.* at 464, 500 S.E.2d at 702.
[112] *Id.* (emphasis added).

parties in light of all the evidence presented."[113] As set forth in these Initial Comments, the Companies cannot meet their evidentiary burden, and therefore, the proposed tariffs should be rejected notwithstanding the MOU.

It bears mentioning that the MOU has not fared well in other proceedings. For instance, in separate dockets, the Public Staff recommended that the Commission reject the Smart Saver incentive portion of the MOU.[114] In fact, a virtually identical Smart Saver incentive, which was part of the SC MOU, was rejected by the PSCSC on January 13, 2022.[115]

Settlement agreements are part of a give-and-take process. In exchange for an incentive, a party to a settlement agreement might agree to a separate contractual term which, without the incentive, would otherwise be completely unpalatable. In light of the give-and-take nature of settlements, where one settlement term is rejected, arguably there is an erosion of the underlying basis for other portions of the settlement agreement. To be specific, if the Commission rejects the Smart Saver incentive—which is part of the MOU but the subject of separate dockets[116]—then the MOU should be completely disregarded by the Commission in the present docket.

---

[113] *Id.* at 466, 500 S.E.2d at 703

[114] Comments of the Public Staff, March 15, 2022, NCUC Docket Nos. E-2 Sub 1287 & E-7 Sub 1261.

[115] PSCSC, Docket Nos. 2021-143-E & 2021-144-E, Commission Directive, January 13, 2022.

[116] NCUC Docket Nos. E-2 Sub 1287 & E-7 Sub 1261

CONCLUSION

The Companies' proposed NEM tariffs violate House Bill 589 and are unsupported by the evidence. For the reasons discussed herein, the Commission should reject the Joint Application. As required by House Bill 589, the Commission should lead a cost-benefit analysis of solar generation, which would include a Commission-led Value of Solar Study. Only upon the conclusion of these studies should new NEM tariffs be proposed by the Companies.

This the 29th day of March, 2022.

/s/ Matthew D. Quinn
Matthew D. Quinn
N.C. Bar No. 40004
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612
mdq@lewis-roberts.com
Telephone: 919-981-0191
Facsimile: 919-981-0199

Attorney for NC WARN, NCCSC & Sunrise Durham

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon all counsel of record by email transmission.

This the 29th day of March, 2022.

/s/ Matthew D. Quinn

Matthew D. Quinn

Attorney for NC WARN, NCCSC & Sunrise Durham

Attachment A

Report Responding to Deficiencies in the Duke Energy NEM Application, by Mr. Powers

Report Responding to Deficiencies in the Duke Energy NEM Application

March 28, 2022, Bill Powers, P.E.

This report addresses deficiencies in the analyses prepared by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke Energy" or the "Companies") to support their proposed new net energy metering ("NEM") solar tariffs. The terms of the new tariffs are reflected in the Memorandum of Understanding ("MOU") filed by Duke Energy with the North Carolina Utilities Commission ("NCUC" or "Commission") as part of the Companies' November 29, 2021 Joint Application for Approval of Net Energy Metering Tariffs (the "Application") in Docket No. E-100, Sub 180.[1] Duke Energy proposes to implement the new NEM tariffs in 2023.[2] HB 589 does not set a deadline for establishing new NEM rates, and the statute allows legacy retail customers to keep their current rates until January 1, 2027.[3]

The MOU filed by Duke Energy with the Commission in its Application is functionally similar to the terms of the NEM MOU between Duke Energy and several other parties[4] that was agreed to in South Carolina in September 2020 ("SC MOU").[5] The primary goal of the SC MOU was to address the requirement, per the South Carolina Energy Freedom Act, for a new NEM structure in South Carolina by June 2021. However, the terms of the SC MOU required that the parties agree to the general principles of the settlement in both South Carolina and North Carolina.[6]

---

[1] The explicit terms of the new NEM tariffs are attached to the Application as Exhibits 1 & 2.
[2] Application, p. 13 ("If approved by the Commission, the NEM Tariffs will be available to customers who submit an application on or after January 1, 2023.").
[3] N.C. Gen. Stat. § 62-126.4(c) ("Retail customers that own and install an on-site renewable energy facility and interconnect to the grid prior to the date the Commission approves new metering rates may elect to continue net metering under the net metering rate in effect at the time of interconnection until January 1, 2027.").
[4] "This MEMORANDUM OF UNDERSTANDING (this "MOU") is made as of September 16, 2020 (the "Effective Date"), by and among Duke Energy Carolinas, LLC ("DEC"); Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies"); North Carolina Sustainable Energy Association; Southern Environmental Law Center on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever; Sunrun Inc.; and Vote Solar (collectively, "Clean Energy Advocates") (the Clean Energy Advocates together with the Companies are referred to as the "Parties" and individually as a "Party")."
[5] DEC, DEP, and Clean Energy Advocates, Memorandum of Understanding, Solar Choice Program/Solar Choice Tariff, September 16, 2020 (in response to requirements of South Carolina Act 62),
[6] SC MOU, p. 1 ("The Parties intend to work collaboratively to advance the terms of this [SC] MOU, including engaging other stakeholders on this matter in advance of filing the Solar Choice Tariffs in South Carolina and to obtain the PSCSC and the North Carolina Utilities Commission ("NCUC") approvals necessary to effectuate this [SC]

I. Qualifications of Bill Powers, P.E.

Bill Powers, P.E., is the principal of Powers Engineering, an energy and environmental consulting firm. Mr. Powers has a BS in mechanical engineering from Duke University and an MPH in environmental science from UNC-Chapel Hill. He is a registered professional engineer in California and Missouri and has forty years of professional experience. Mr. Powers is an expert witness in the ongoing NEM successor tariff proceeding before the California Public Utilities Commission, Rulemaking R.20-08-020, *Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering*. He has previously provided expert testimony before the NCUC in Docket No. E-100, Sub 165, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's *2020 Integrated Resource Plans*. Mr. Powers also authored *"North Carolina Clean Path 2025"* in 2017.

II. Summary

The proposed successor NEM tariff developed by Duke Energy will substantially reduce the economic value of NEM solar for new residential customers. Duke Energy does not adequately credit residential NEM solar for its beneficial economic impact in reducing or eliminating expansion of the transmission and distribution ("T&D") system that would otherwise be necessary to accommodate load growth and grid congestion at times of peak demand. When the economic benefit of these avoided T&D expenditures is properly credited, there is no cost-shift to address with the residential NEM tariff presented in the Application.

The settling parties are promoting the MOU as a NEM solar model for the rest of the country, on the assertion that it effectively addresses the alleged (by the utilities) cost-shift favoring NEM solar customers under a traditional NEM tariff.[7] Duke Energy's underestimation of the benefits of NEM solar is the basis for the alleged cost-shift. A comprehensive accounting

---

MOU. The Parties ultimately desire to avoid a contentious adversarial proceeding before the PSCSC or the NCUC by collaborating to implement the Solar Choice Tariffs within the spirit of Act 62 and North Carolina law.")

[7] Utility Dive, *Duke-solar industry breakthrough settlement aims to end rooftop solar cost shift debates*, September 16, 2020. "A landmark settlement between Duke Energy and distributed energy resources (DER) advocates in North and South Carolina could remake the rooftop solar sector and be a model for ending regulatory disputes across the country."

of the benefits of NEM solar by Duke Energy would have eliminated the justification for this Application.

The major components of the proposed NEM tariff in North Carolina are: 1) a minimum monthly bill, 2) summer and winter time-of-use ("TOU") on-peak and off-peak windows, and 3) mandatory on-peak and off-peak TOU pricing. Additional NEM tariff components include critical peak pricing (CPP), non-bypassable charges, and a grid access fee ("GIF") for systems greater than 15 kW. The proposed NEM tariff is linked to a $0.36/watt incentive payment for all-electric solar customers that is under consideration in a separate docket.[8,9]

Duke Energy has to date provided no substantiation to support its shift of the NEM summertime on-peak period from 2 pm – 8 pm to 6 pm – 9 pm. In the relevant January 2022 Commission Order, the only technical support offered is a 12-page narrative summary of a July 2021 PowerPoint presentation it gave to the informal stakeholder Fast Track Working Group, wherein Duke Energy summarizes its internal TOU modeling.[10] This summary includes ten slides taken directly from the July 2021 stakeholder workshop and a final page summarizing the opinion of stakeholders of the proposed TOU periods. This is the sole "evidentiary" support for this dramatic shift in the summer on-peak period. In contrast, DEC conducted extensive analysis prior to determining that a summer on-peak window of 2 pm – 8 pm most accurately captured the summer peak demand profile.[11] The sun is on its way down by 6 pm, and little solar energy will be generated after 6 pm.

---

[8] Duke Energy Carolinas, LLC, Application for Approval of Smart $aver Solar Energy Efficiency Program Docket No. E-7, Sub 1261, December 16, 2021, Exhibit 1, p. 3. "Initial incentive for solar PV will be $0.36/Watt-dc and is based upon the direct current (DC) nameplate rating of the Customer's solar PV system."

[9] The cumulative incentive payment is $0.39/Watt-dc, as explained in Exhibit B to the Application: "The Companies will offer a cumulative $0.39/Watt-dc incentive for new residential NEM customers that meet the availability requirements for DEC Schedule RE, such that all energy required for all water heating, cooking, clothes drying, and environmental space conditioning must be supplied electrically. The upfront rooftop solar incentive is $0.36/Watt-dc (the "Rooftop Incentive") and may be assigned to a solar leasing company if the customer is in a lease arrangement."

[10] DEP Docket No. E-2, Sub 1280, *Order Approving Time-of-Use Rate Designs*, January 6, 2022, p. 2 (reference to Exhibit 1 – Duke Energy's September 30, 2021 TOU Period Technical Report –- to DEP's application).

[11] DEC Docket No. E-7, SUB 1146, Docket No. E-7, SUB 1253, *Order Approving Rate Designs*, August 25, 2021, p. 2. "On August 2, 2021, DEC filed the Final Report on Dynamic Pilot Rates which included the results of numerous customer surveys and customer bill analyses completed as part of the pilot."

The Petition only refers to a "solar program tailored to low-income customers as a potential future EE or demand response program."[12] An equitable, well-funded on-bill financing and/or on-bill repayment program, tied to the electric meter ("tariffed") and not to the customer, would potentially lessen the equity barriers in the NEM settlement. The tariff is also deficient because it fails to contain provisions for fast-growing battery storage technology.

The reduction in the economic value of residential NEM solar will be approximately 30 percent based on Duke Energy's calculations.[13] The proposed NEM tariff will impede the growth of NEM solar and is based on the incomplete quantification by Duke Energy of the benefits of NEM solar. The Commission should conduct an impartial assessment of the costs and benefits of NEM solar and use this assessment to establish a just and reasonable NEM successor tariff.

III. Putting the Alleged NEM Cost-Shift in Context

The alleged cost-shift from NEM residential customers to non-NEM residential customers was approximately $10 million at the end of 2020.[14] This is about 1/100th the $1 billion per year that residential DEC and DEP customers pay in excess of what the DEC and DEP full cost-of-service ("COS") studies indicate they should be paying.[15] In percentage terms, DEC and DEP residential customers are paying 25 percent more than their full COS.[16]

---

[12] Petition, pdf p. 46.

[13] **Attachment E**, Duke Energy's Response to the Public Staff's Data Request No. 1-3(f) (xls spreadsheet "Financial Forecast" tab, lines 26-27). Duke Energy does not include the incentive payment in its comparative NEM economic value calculations.

[14] EIA, *2020 NC Electricity Profile*, November 4, 2021, Table 11. There were 20,559 residential NEM customers in North Carolina at the end of 2020 with a total installed capacity of 140.8 MW; Duke Energy response to NC WARN DR1-11 (xls spreadsheet, Marginal Cost Study), current DEC RE cost-shift = $360/yr, current DEC RS cost-shift = $372/yr, current DEP RES cost-shift = 708/yr. Average cost-shift = $480/yr. Therefore, total NEM cost-shift at end of 2020 = 20,559 NEM customers x $480/yr = $9.87 million/yr.

[15] **Attachment F**, Duke Energy's Response to NC WARN's Data Request No. 2-1 [DEC FERC Form 1, p. 300, 2019 residential customer retail sales = $3,051,598,700; DEP FERC Form 1, p. 300, 2019 residential customer retail sales = $2,169,136,266; Total DEC + DEP 2019 residential retail sales = $5,220,734,966. Duke Energy response R1-2 to Public Staff DR No. 1, Item 2, embedded cost-of-service, Test Year 2018 [DEC RE customers = $960,462,442; DEC RS customers = $1,378,219,081; DEP RES customers = 1,850,159,825. Total cost to serve DEC + DEP residential customers = $4,188,841,348.] Annual difference, (DEC + DEP residential retail sales) – (DEC + DEP residential cost-of-service) = $5,220,734,966 - $4,188,841,348 = $1,031,893,618.

[16] Percentage that DEC + DEP residential customers pay above their full cost-of-service: $1,031,893,618 ÷ $4,188,841,348 = 0.246 (24.6 percent).

The amount of the alleged NEM cost-shift is insignificant compared to additional costs already being borne by DEC and DEP residential customers relative to other customer classes. The Commission, with its mandate to address cost-causation equity, should prioritize rectifying the cost-shift from other customer classes onto residential customers. The real cost-shift onto residential customers is 100 times greater than the alleged cost-shift from NEM residential customers onto non-NEM residential customers.

H.B. 589 does not distinguish between residential and non-residential customers when it addresses the NEM cost-shift issue. HB 589 states only, "*The Commission shall establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service*."[17] However, the Application focuses exclusively on addressing the alleged cost-shift between two subsets of residential customers, NEM residential customers and non-NEM residential customers. There is no attempt to assess the alleged cost-shift between NEM customers as a whole (both residential NEM and non-residential NEM customers), and non-NEM residential and non-residential customers.

In fact, the cost-shift between NEM and non-NEM customers, even at much higher NEM deployment levels than have occurred to date in North Carolina, is likely to favor the non-NEM customers. That was the result of an analysis of the NEM cost-shift based on full COS was done in California in 2013.[18] The analysis reviewed the cost-shift impact of NEM solar in California through the end of 2011, when California had 122,000 NEM customers and 1,110 MW of installed NEM solar.[19] In contrast, North Carolina had 21,362 NEM customers and 187 MW of installed NEM capacity at the end of 2020, about one-sixth the number of NEM customers included in the scope of the cost-shift analysis done in 2013 in California.[20]

The California analysis found that NEM residential customers were paying 81 percent of their full COS, and that these residential customers had been paying 154 percent of their full COS prior to adding NEM.[21] NEM non-residential customers were paying 112 percent of their

---

[17] N.C. Gen. Stat. § 62-126.4(b).
[18] California Public Utilities Commission, *California Net Energy Metering Ratepayer Impacts Evaluation*, October 2013.
[19] Ibid, p. 24.
[20] EIA, *2020 North Carolina Electricity Profile*, November 2021, Table 11.
[21] California Public Utilities Commission, *California Net Energy Metering Ratepayer Impacts Evaluation*, October 2013, p. 10.

full COS, and these non-residential had been paying 122 percent of their full COS prior to adding NEM.[22] Collectively the NEM residential and non-residential customers were paying 103 percent of their full COS. In plain English, the NEM customers were collectively paying more than their full COS – $12 million per year more – providing net cost benefits to non-NEM customers.[23]

DEC and DEP residential customers are paying 25 percent more than their full COS now.[24] Duke Energy underscores in its Application that each NEM customer must pay its full COS:[25]

> H.B. 589 requires the Commission to investigate the costs and benefits of customer-sited generation and to revise NEM rates to ensure that each NEM customer "pays its full fixed cost of service."

The Commission should prioritize rectifying the cost-shift from other rate classes onto DEC and DEP residential customers, a cost-shift that is 100 times greater than the cost-shift alleged by Duke Energy between NEM residential and non-NEM residential customers. DEC and DEP residential customers should only be paying their full COS, not more. The rate class-by-rate class cost-shifts should be addressed before the Commission expends significant effort to adjudicate the alleged cost-shift between NEM residential customers and non-NEM residential customers.

IV. The Minimum Monthly Bill ("MMB")

The Application/MOU includes a MMB for NEM customers of $22 per month for DEC and $28 per month for DEP.[26] The following charges can be used to offset the MMB: 1) basic facilities charge ("BFC"), 2) portions of the volumetric energy charge for purchased grid power, and 3) charges for riders. Duke Energy identifies the reason for the MMB as *"recovery of customer and distribution costs."*[27] Duke Energy residential NEM solar customers already pay a BFC of $14 per month (except for customers on two DEP TOU rate schedules who pay $16.85

[22] Ibid.
[23] Ibid.
[24] ($5,220,734,966 - $4,188,841,348) ÷ $4,188,841,348 = 0.246 (24.6 percent)
[25] Application, p. 10.
[26] Application, p. 14.
[27] MOU, p. 2.

per month),[28] which Duke Energy indicates "*covers fixed costs of providing service to your location as well as maintaining customer records, billing and other transactions affecting your account*."[29] The BFC range is presently at the high end of BFC charges paid by utility customers around the country.[30]

The BFC would be a component of the MMB under the terms of the NEM tariff described in the Application. Duke Energy prepared a NEM bill calculator in response to the first data request by Public Staff.[31] In the DEC example provided in the NEM bill calculator, only $9.92 of the NEM customer's $58.82 of accrued monthly volumetric energy charges (for 405 kWh of purchased electricity) count toward offsetting the MMB. This is because Duke Energy has determined that only a relatively small portion of the volumetric energy charge is usable to offset the MMB.

Energy production charges and production and transmission demand charges, which together comprise about two-thirds of the DEC volumetric energy charge,[32] are not eligible to offset the MMB. Duke Energy identifies that the purpose of the MMB is to "*recover customer and distribution costs*."[33] By restricting charges eligible to offset the MMB to only these two elements of the volumetric energy charge, NEM customers – as shown in the DEC example – will need to accrue substantial monthly volumetric charges ($58.82 per month) to offset relatively small MMB "gap" charges ($9.92 per month). The same situation holds for DEP residential NEM customers.[34]

---

[28] Duke Energy Rates (DEC/DEP): https://www.duke-energy.com/home/billing/rates, accessed 3/11/22.

[29] Winston-Salem Journal, *Ask SAM: What is this new charge on my Duke energy bill?*, August 5, 2020: https://journalnow.com/news/ask_sam/ask-sam-what-is-this-new-charge-on-my-duke-energy-bill/article_5695248d-159e-5a89-a584-e23861b066c8.html.

[30] EEI, *Primer on Rate Design for Residential Distributed Generation*, February 2016, p. 7: https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Forms/AllItems.aspx. "Most residential rates currently offered in the U.S. include a fixed monthly charge (sometimes called a customer charge, basic service charge or customer service charge) that is approximately in the range of $5-$15/month along with an energy charge."

[31] **Attachment G**, Duke Energy's Response to the Public Staff's Data Request No. 1-1 (xls NEM bill comparison spreadsheet).

[32] **Attachment H**, Duke Energy's Response to NC WARN's Data Request No. 1-11 (xls spreadsheet), tabs "DEC Unit Costs," "DEP Unit Costs."

[33] **Attachment I**, Duke Energy's Response to NC WARN's Data Request No. 5-1 (stating that "the $9.92 referenced is not a wholesale value, but rather the portion of volumetric rates that recover customer and distribution costs.").

[34] **Attachment G**, Duke Energy's Response to the Public Staff's Data Request No. 1-1 (xls NEM bill comparison spreadsheet).

In any case, there is no compelling evidence supporting the notion that there is a cost-shift from rooftop solar customers, and therefore, there is no factual basis for a MMB. NEM solar can reduce or eliminate expansion of the transmission and distribution ("T&D") system that would otherwise be necessary to accommodate load growth and grid congestion at times of peak demand. These are categorized as "grid reliability" T&D projects. Duke Energy's avoided T&D calculation assumes incorrectly that NEM solar is only deferring T&D expansion that will inevitably occur, and not eliminating it.[35]

The value of NEM for eliminating capital investment in T&D expansion is substantially greater than the avoided T&D value of NEM that Duke Energy assumes in its NEM cost-shift analysis.[36] This has been evaluated in the ongoing NEM proceeding in California,[37] a state with 12,000 MW of installed NEM solar capacity.[38] High voltage (> 200 kV) transmission planning in California is conducted by the California Independent System Operator ("CAISO"). CAISO identified the unanticipated growth in NEM in Pacific Gas & Electric (PG&E) territory over a three-year period, 1,540 MW above the forecast projection, as a primary reason for the cancellation of $2.6 billion worth of approved PG&E transmission projects.[39] The annualized avoided cost of this eliminated transmission expense per NEM system can readily be calculated with this information.

As detailed in **Attachment B**, the avoided cost of high voltage transmission alone would be about $935 per year per typical 9 kW DEC or DEP system. This is much greater than the NEM avoided T&D value assumed by Duke Energy of $196 to $247 per year for DEC and $127 per year for DEP.[40] The avoided new transmission value of $935 per year is roughly equivalent to

---

[35] On March 1, 2022, NC WARN requested, in its Data Request No. 4-4, that Duke Energy provide the workpapers and calculations that support the avoided T&D values it provides in its response NC WARN's Data Request No. 1-11. As of the date of this filing, Duke Energy's only response is "work in progress." (*See* **Attachment J**, Duke Energy's Response to NC WARN's Data Request No. 4-4).

[36] **Attachment H**, Duke Energy response to NC WARN DR 1-11 Marginal Cost Study (xls spreadsheet).

[37] CPUC Rulemaking R.20-08-020, *Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering*, August 27, 2020: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R2008020.

[38] California Distributed Generation Statistics (website), accessed March 23, 2022: https://www.californiadgstats.ca.gov/.

[39] *See* **Attachment B.**

[40] **Attachment H**, Duke Energy's Response to NC WARN's Data Request No. 1-11, Marginal Cost Study (xls spreadsheet).

the alleged DEC residential NEM cost-shift of $909 to $1,025 per year, and DEP residential NEM cost-shift of $1,171 per year, identified by Duke Energy.[41]

An even greater potential savings is achieved by NEM solar, as much as $1,600 per year per 9 kW NEM system as detailed in **Attachment C**, when NEM solar substitutes for remote utility-scale solar that is reliant on new or upgraded transmission to enable it to be delivered to demand centers. Duke Energy projects that DEC and DEP will collectively add 2,652 MW of utility-scale solar between 2021 and 2026.[42] If utility-scale solar continues to be concentrated in southeastern North Carolina, substantial transmission expansion will be necessary to deliver this solar power to DEC and DEP customers living in the major urban centers of the state in western and central North Carolina (Charlotte, Greensboro/Winston-Salem, Raleigh-Durham).

DEC and DEP combined are investing about $1 billion per year on new reliability and expansion-related transmission and distribution projects.[43,44] The substitution of NEM solar in the demand centers of North Carolina where DEC and DEP customers are concentrated would potentially eliminate the need for transmission reinforcement between these demand centers and rural southeastern North Carolina utility-scale solar farms, and potentially for expansion-related distribution projects.

---

[41] Ibid.

[42] **Attachment K**, Duke Energy's Responses to NC WARN's Data Request Nos. 1-5 (DEC) and 1-10 (DEP). Utility-scale solar development will continue beyond 2026. Assuming Duke Energy North Carolina holds the same rate of utility-scale solar expansion in the 2027-2031 timeframe, more than 5,000 MW of utility-scale solar will be added in North Carolina by 2031.

[43] NCUC, Docket No. E-7 SUB 1214, *Direct Testimony of Jay W. Oliver for DEC, LLC*, September 30, 2019, pp. 16-17. "Over the past two years, approximately $600 million was invested in the transmission system and $1.6 billion in the distribution system . . . In the transmission system, approximately 33 percent of investment was driven by capacity requirements to serve load . . . Approximately 31 percent of investment was driven by standard reliability improvement programs . . . Approximately 49 percent of the Company's distribution expenditures over the last two years are for load expansion-related work."

[44] NCUC, Docket No. E-2 SUB 1219, *Direct Testimony of Jay W. Oliver for DEP, LLC*, October 30, 2019, p. 15 and p. 17. "Over the past two years, more than $0.3 billion was invested in the transmission system and approximately $1.0 billion in the distribution system . . . In the transmission system, approximately 46 percent of investment was driven by capacity requirements to serve load . . . Approximately 48 percent of investment was driven by reliability improvement and maintenance programs . . . Approximately 51 percent of the Company's distribution expenditures over the last two years are for load expansion-related work."

V. NEM Economic Value Reduction for Modeled NEM Customer

Duke Energy models the decline in NEM economic value for three NEM system sizes, 8.37 kW and 9.95 kW (DEC), and 9.09 kW (DEP).[45] These systems are designed to produce about 75 percent of monthly electricity demand.[46] Duke Energy shows a 30 percent reduction in value for these NEM systems under the proposed tariff and without the incentive payment.[47]

Duke Energy determined that the Year 1 NEM savings under the DEC residential RS tariff for an 8.37 kW solar array would decline from $75.76 per month to $53.59 per month, a 29 percent decline in NEM savings. The Year 1 NEM savings under the DEC residential RE tariff for a 9.95 kW solar array would decline from $85.42 per month to $59.03 per month, a 31 percent decline in NEM savings.[48]

The NEM savings reduction is comparable in DEP territory. The Year 1 NEM savings under the DEP residential RES tariff for a 9.09 kW solar array would decline from $97.61 per month to $68.44 per month, a 30 percent decline in monthly NEM savings.[49]

The preceding calculations are for a system without the incentive payment for all-electric customers. The proposed SC NEM tariff, based on the PSCSC Order and assuming the incentive payment, would represent a 10 percent reduction in the economic value of a typical larger NEM system, according to an expert witness testifying in that case.[50] Therefore, the

---

[45] **Attachment E**, Duke Energy's Response to the Public Staff's Data Request No. 1-3(f) (xls spreadsheet "Financial Forecast" tab), showing 8.37 kW system with monthly demand of 1,166 kWh for RS customer. A 9.95 kW system, for a customer with 1,463 kWh of monthly demand, is shown for DEC RE customer. A 9.09 kW system with monthly demand of 1,303 kWh is evaluated for DEP RES customer.

[46] Ibid. DEC RS Year 1: (886 kWh-month/1,166 kWh-month) = 0.759 (75.9 percent); DEC RE Year 1: (1,072 kWh-month/1,463 kWh-month) = 0.733 (73.3 percent); DEP RES Year 1: (971 kWh-month/1,303 kWh-month) = 0.745 (74.5 percent);

[47] **Attachment E**, Duke Energy's Response to the Public Staff's Data Request No. 1-3(f), DEC 2019 xls spreadsheet 12 Oct 2021 ("Financial Forecast" tab); DEP 2019 xls spreadsheet 12 Oct 2021 ("Financial Forecast" tab).

[48] Ibid, lines 26-27. DEC RS Year 1 [("current savings" - "new savings") ÷ "current savings"] = [($75.76/mo - $53.59/mo) ÷ $75.76/mo] = 0.292 (29.2 percent decrease in value). DEC RE Year 1 [("current savings" - "new savings") ÷ "current savings"] = [($85.42/mo - $59.03/mo) ÷ $85.42/mo] = 0.309 (30.9 percent decrease in value).

[49] DEP RES Year 1 [("current savings" - "new savings") ÷ "current savings"] = [($97.61/mo - $68.44/mo) ÷ $97.61/mo] = 0.299 (29.9 percent decrease in value).

[50] PSCSC, Docket Nos. 2020-264-E & 2020-265-E, Order No. 2021-390, Order Approving Stipulations, Approving Interim Riders, and Establishing Solar Choice Tariffs, May 30, 2021, at pp. 48 & 50: "As for the impacts of the compromise on NEM customers, Witness Beach explained that customers under the Solar Choice Tariffs will see only a 'moderate reduction in the bill savings available to solar customers when compared with current NEM tariffs, on the order of a 10% decrease for a typical customer'. . . . No testimony was presented refuting the points made above."

incentive payment appears to improve the negative economic impact of the proposed NEM tariff from a 30 percent reduction in value to a 10 percent reduction in value.

VI. Contradiction in Duke Energy NEM Growth Projection

Duke Energy counterintuitively projects a substantial increase in the rate of installation of NEM systems in DEC and DEP service territories in North Carolina in the 2021-2026 timeframe, despite proposed NEM tariffs that will offer substantially less economic benefit to new residential NEM customers. North Carolina as a whole added 56 MW of NEM solar in 2020, of which 49.5 MW – about 90 percent – was residential NEM.[51] Duke Energy projects that DEC and DEP collectively will average an addition of 82 MW per year of NEM solar in 2021-2026,[52] a nearly 50 percent increase year-after-year over the actual 2020 NEM installation rate for the state of North Carolina.[53]

No evidence is provided by Duke Energy to support its projection of a substantially increased rate of adoption of NEM systems in the 2021-2026 timeframe. It is uncontested that the economic benefit of NEM systems to new customers will be reduced under the proposed NEM tariff.[54] Duke Energy is attempting to have it both ways. It is forecasting substantial growth in the NEM solar installation rate, which in North Carolina is overwhelmingly comprised of residential NEM systems, while it substantially reduces the savings achievable with residential NEM solar.

---

[51] EIA, *2020 North Carolina Electricity Profile*, November 4, 2021. Table 11. Net metering, 2010 through 2020: https://www.eia.gov/electricity/state/northcarolina/. These NEM statistics are conservative for DEC and DEP, as they include other investor-owned utility, municipal, and rural cooperative NEM systems in North Carolina as well.

[52] **Attachment L**, Duke Energy's Response to NC WARN's Data Request Nos. 1-4 & 1-9. DEC NEM installation rate, end of 2021 through 2026 (5 years) = 274 MW. Annual NEM installation rate = 274 MW ÷5 years = ~55 MW/yr. DEP NEM installation rate, end of 2021 through 2026 = 134 MW. Annual NEM installation rate = 134 MW ÷5 years = ~27 MW/yr.

[53] 82 MW/yr ÷ 56 MW/yr = 1.464 (46 percent increase)

[54] Application, p. 13. Duke Energy proposes to implement the new NEM tariff on January 1, 2023.

VII. The Existing Net Metering Tariff Meets the H.B. 589 Mandate That Solar Customers Pay Their Full COS

The existing NEM tariff meets the H.B. 589 mandate that NEM customers pay their full COS.[55] This was demonstrated in South Carolina where the Duke Energy SC MOU, largely similar to the terms included in the present Application, was initially litigated. There are three pertinent investor-owned utilities in South Carolina: DEC, DEP, and Dominion Energy South Carolina ("DESC"). The DESC NEM proceeding, which did not begin from the starting point of a settlement, resulted in the approval of a new residential NEM tariff based on the determination that the existing NEM tariff was equitable and not causing a significant cost-shift onto non-solar customers. The new DESC residential NEM tariff may in fact be better than the NEM tariff it replaced, given the advantageous 2 pm to 7 pm on-peak summertime window and the high summer on-peak rate of $0.27/kWh.[56]

DESC was not a party to the Duke Energy SC MOU. The DESC rooftop solar tariff was separately adjudicated in a formal proceeding, with the Order in that proceeding issued on May 29, 2021.[57]

The DESC NEM proposal presented in its application in South Carolina was comparable in numerous respects to the proposed Duke Energy NEM tariffs in the present docket. The DESC NEM proposal in South Carolina included:[58]

- $19.50 per month BFC;
- Subscription Fee of $5.40 per kW of installed renewable generation capacity (to recover fixed transmission and distribution system costs);
- 4 pm to 8 pm summer on-peak (to align more closely with DESC's projected future peak periods);

---

[55] Application, p. 10. H.B. 589 requires the Commission to investigate the costs and benefits of customer-sited generation and to revise NEM rates to ensure that each NEM customer "pays its full fixed cost of service." N.C. Gen. Stat. § 62-126.4(b).

[56] Public Service Commission of South Carolina, Docket No. 2020-229-E, Order No. 2021-391, *Order Establishing Solar Choice Tariff for New Customers Beginning June 1, 2021*, May 29, 2021, p. 99. Order requires DESC residential NEM customers to take service under Rate 5 TOU rate, which has summer on-peak period of 2 pm – 7 pm and an on-peak rate of $0.27036/kWh.

[57] Ibid.

[58] Public Service Commission of South Carolina, *Docket No. 2020-229-E, Direct Testimony of Allen W. Rooks on Behalf of Dominion Energy South Carolina, Inc.*, December 15, 2020, p. 6.

- On-peak summer rate of $0.16749 per kWh; and
- Off-peak summer rate of $0.06735 per kWh.

The PSCSC rejected the DESC NEM proposal. The PSCSC's Order on DESC's NEM proposal concluded that DESC's cost-shift analysis was flawed and that there was no significant cost-shift when the long-term benefits of NEM solar are accounted for, stating in the Findings of Fact (No. 1 and No. 23):[59]

> 1) DESC's methodology for calculating cost shift, as discussed in the testimony of Witness Everett, is unreasonable because its methodology does not consider all of the benefits of customer-generated solar,
>
> 23) The portions of the Joint Solar Choice Proposal approved in this Order do not cause a significant potential cost-shift when considering the cost to serve residential solar customer-generators under DESC's existing embedded cost of service methodology.

The terms of the DESC NEM tariff ultimately approved by the PSCSC are substantially more favorable than the Duke Energy MOU terms in either South Carolina or North Carolina. The principal elements of each tariff are compared in Table 1.

Table 1. Comparison of principal elements of DESC, Duke Energy NC, Duke Energy SC NEM tariffs[60]

Utility	BFC/MMB	Summer TOU, on-peak period	Summer TOU, rates ($/kWh)
DESC	$9.00/$13.50	2 pm – 7 pm	on-peak: 0.270 off-peak: 0.088
DEC NC	$14/$22	6 pm – 9 pm	on-peak: 0.192 off-peak: 0.084
DEP NC	$14/$28	6 pm – 9 pm	on-peak: 0.193 off-peak: 0.098
DEC SC	$13.09/$30	6 pm – 9 pm	on-peak: 0.155 off-peak: 0.091
DEP SC	$14.63/$30	6 pm – 9 pm	on-peak: 0.163 off-peak: 0.100

[59] Public Service Commission of South Carolina, Docket No. 2020-229-E, Order No. 2021-391, *Order Establishing Solar Choice Tariff for New Customers Beginning June 1, 2021*, May 29, 2021, pp. 23-24 & 28.

[60] For DEC SC:
https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/rates/electric-sc/scschedulerstou.pdf
For DEP SC:
https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/rates/electric-sc/r3-sc-schedule-r-stou.pdf

The technical consultant to the clean energy parties that signed the Duke Energy MOUs in both South Carolina and North Carolina submitted extensive "value of NEM solar" testimony in October 2020 in the PSCSC NEM proceeding.[61] The consultant's testimony in the DESC NEM proceeding states:

> There is not presently a cost shift from solar customers to non-participating ratepayers, and distributed solar is a cost-effective resource for DESC ratepayers. There is also a small net benefit for customers who install solar, indicating that the market should continue to grow, albeit slowly, under the present net metering tariffs. Finally, there are significant, quantifiable societal benefits from distributed solar, including public health benefits from reduced air pollution and from mitigating the damages from carbon emissions.[62]

The consultant observed that when standard utility cost-effectiveness tests are applied, the current NEM tariff structure does not shift any costs onto non-solar customers. In addition, the consultant noted that there are additional economic and societal benefits that utilities do not fully value in assessing the cost-effectiveness of solar.[63] The PSCSC concurred in its May 29, 2021 Order defining the new DESC NEM tariff that there is no significant cost-shift between NEM solar customers and non-solar customers under the new NEM tariff.[64]

One element of the DESC NEM proposal rejected by the PSCSC, specifically DESC's proposed time-of-use ("TOU") window, is particularly relevant to the Application. Duke Energy has to date provided no substantiation to support its shift of the NEM summertime on-peak period from 2 pm – 8 pm to 6 pm – 9 pm, other than to point to a summary of an overview

[61] PSCSC, Docket No. 2019-182-E, South Carolina Energy Freedom Act: Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators, *Rebuttal Testimony of R. Thomas Beach on Behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, The Solar Energy Industries Association, and the North Carolina Sustainable Energy Association*, October 29, 2020.

[62] *Id.* at 2.

[63] Ibid, Figure ES-1, p. 2.

[64] Public Service Commission of South Carolina, Docket No. 2020-229-E, Order No. 2021-391, *Order Establishing Solar Choice Tariff for New Customers Beginning June 1, 2021*, May 29, 2021, pp. 23-24 & 28. Findings of Fact: 1) DESC's methodology for calculating cost shift, as discussed in the testimony of Witness Everett, is unreasonable because its methodology does not consider all of the benefits of customer-generated solar; 23) The portions of the Joint Solar Choice Proposal approved in this Order do not cause a significant potential cost-shift when considering the cost to serve residential solar customer-generators under DESC's existing embedded cost of service methodology.

PowerPoint presentation on its TOU modeling that it presented to the stakeholder Fast Track Working Group in July 2021.[65] In the DESC proceeding, this lack of supporting documentation was the basis upon which the PSCSC rejected the proposed NEM summer on-peak window of 4 pm – 8 pm in favor of the 2 pm – 7 pm summer on-peak window that had been previously established by DESC based on cost-causation principles.[66]

VIII. Unsupported and Late Summertime On-Peak TOU Period

Under the Application, solar exports are netted against imports during the TOU window each month. Any monthly exports of solar power in excess of the netted amounts are compensated at avoided cost, which is currently 2.68 cents per kWh in DEC and 2.64 cents in DEP.[67] The current NEM tariff credits NEM customers for solar exports at the retail rate, with excess export credits rolling over each month and then zeroed-out once a year at the beginning of the summer billing season.

The rate structure proposed in the settlement includes an off-peak rate, an even cheaper "discount" rate (1 – 6 am summer; 1 – 3 am and 11 am – 4 pm winter), higher rate on-peak pricing windows of 6 pm – 9 pm in summer and 6 am – 9 am in winter, and critical peak pricing (CPP) for high demand days.[68] During on-peak and CPP periods, NEM customers pay higher rates. They also get compensated at the on-peak rate when exporting to the grid during these periods. The 6 pm – 9 pm summer window is where Duke Energy asserts the summer

---

[65] DEP Docket No. E-2, Sub 1280, *Order Approving Time-of-Use Rate Designs*, January 6, 2022, p. 2 (reference to Exhibit 1 – Duke Energy's September 30, 2021 TOU Period Technical Report – to DEP's application).

[66] Ibid, p. 99. ("Ordering Paragraphs: 1(a) A requirement to take service under Rate 5 TOU rate (summer 2 pm – 7 pm on-peak period), which provides a more accurate and cost-based rate that can also serve as a platform for additional DERs that a customer-generator may adopt.")

[67] Petition, pdf pp. 31 and 41.

[68] For details of the TOU-CPP windows, see Duke Energy Carolinas, LLC's Compliance Tariffs for Dynamic Rate Pilots and Advanced TOU Rates, Docket Nos. E-7, Sub 1146 and E-7, Sub 1253, Sept. 1, 2021, pdf pp. 54-55 and 57-58: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fa7fce6d-a74a-4dfd-93d4-7982bd0634e1 and Duke Energy Progress, LLC's Compliance Tariffs.
Docket Nos. E-2, Subs 1219 and 1280, Jan. 18, 2022, pdf pp. 8-9:
https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=b7bddd24-0df1-496c-9e39-cdc50803158c.

peak will be in 2026, not where it is now.[69] As noted, Duke Energy has provided no supporting material (workpapers, modeling inputs) for such a projection.[70]

The Application/MOU proposes a summer on-peak rate period of 6 pm – 9 pm. The sun is on its way down by 6 pm, and little solar energy will be generated after 6 pm. Unless the customer has battery storage that can be used to supply household demand in the 6 pm – 9 pm window, the customer will receive almost no on-peak value. In 2020, the DEC summer month peak hour in July, August, and September occurred between 4 pm – 5 pm.[71] The 2020 DEP summer month peak hour occurred in the 4 pm hour.[72] Given the long-term nature of the proposed TOU structure ("at least 10 years" under the MOU), the failure of the proposed TOU hours to accurately reflect Duke Energy's most recent annual peak hour window – to the detriment of NEM customers – is unreasonable.

The previous DEC (pilot) *Residential Service Time-of-Use – Critical Peak Pricing* tariff, implemented in 2019, had a summer peak window of 2 pm – 8 pm, and winter peak period windows of 6 am – 10 am and 6 pm – 9 pm.[73] A 2 pm – 8 pm summer peak window would substantially increase the revenue generated by a solar-only rooftop system on a TOU tariff. This is shown in Figure 1.

[69] DEP Docket No. E-2, Sub 1280, *Order Approving Time-of-Use Rate Designs*, January 6, 2022, p. 2 (reference to Exhibit 1 – Duke Energy's September 30, 2021 TOU Period Technical Report – to DEP's application).

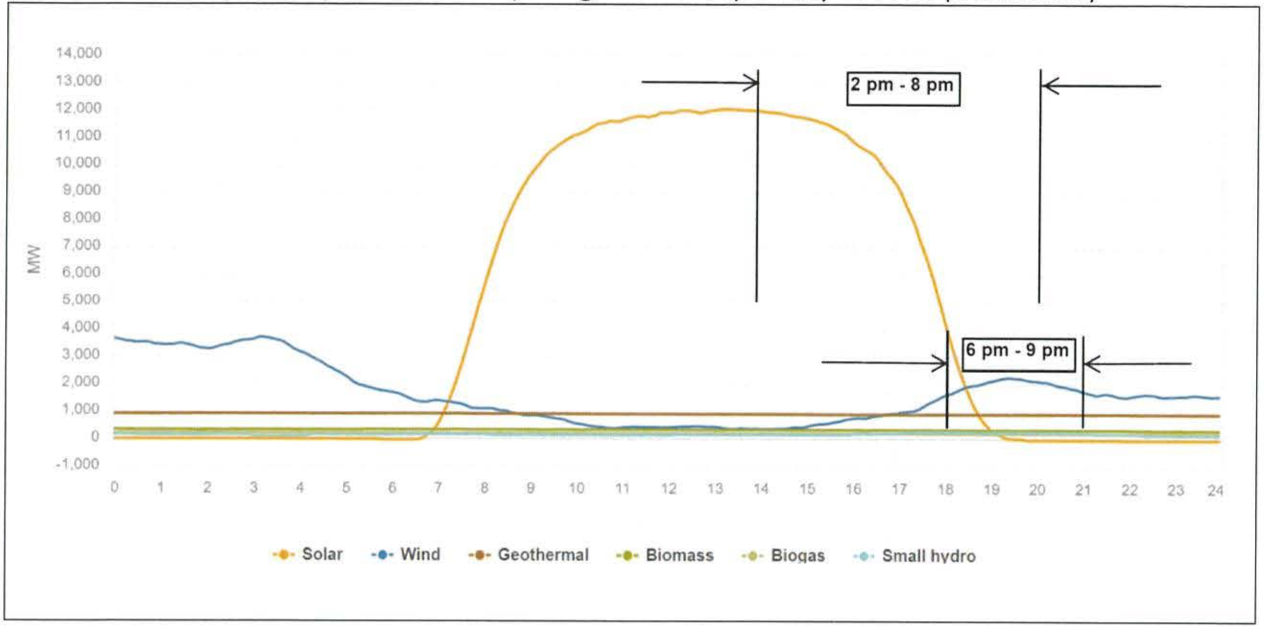
[70] The current actual summer peak occurs in the 4 – 5 pm window in the highest peak summer months of July, August, and September (2020 DEC and DEP FERC Form 1 data), a time of day when NEM solar is very productive (See Figure 1). NC WARN requested in Data Request No. 4-2 (**Attachment M**) that Duke Energy provide its forecast model inputs, calculations, and workpapers that support the on-peak shift to 6 pm – 9 pm. The Duke Energy DR response to NC WARN Item No. 4-2 states "DEP's analysis regarding high-cost time periods during the summer months between 2021 and 2026 was presented in the Comprehensive Rate Design Study stakeholder process and was used to develop the TOU periods approved in Docket No. E-2, Sub 1280."

[71] **Attachment F**, Duke Energy's Response to NC WARN's Data Request No. 2-1 (2020 DEC FERC Form 1s, p. 401b). The peak hour range shown is for July, August, and September, the months with the highest peak demand.

[72] Ibid.

[73] NCUC, Docket No. E-7, Sub 1146, DEC's Revised AMI Rate Design Work Plan and Proposed Dynamic Pricing Pilots, April 1, 2019, pdf pp. 10, 13, 16, 19, 22, 25, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ceff9e7f-7247-42d8-8367-8a468e3c6d93.

Figure 1. Comparison of summer solar production in 2 pm – 8 pm window and 6 pm – 9 pm window[74] (orange curve is quantity of solar production)



The extent of Duke Energy's support for a 6 pm – 9 pm summer peak window is a summary of TOU modeling outputs presented to an informal stakeholder Fast Track Working Group in July 2021.[75] In contrast, the company conducted extensive analysis prior to determining that a summer on-peak window of 2 pm – 8 pm most accurately captured the summer peak demand profile.[76] As noted, Duke Energy has not provided NC WARN with the underlying modeling inputs and assumptions used by Duke Energy to support the major shift in the summertime on-peak windows between the pilot TOU tariff (2 pm – 8 pm) and the permanent TOU tariffs (6 pm – 9 pm).

The PSCSC rejected DESC's attempt to shift the TOU summertime on-peak window from 2 pm – 7 pm to 4 pm – 8 pm in its proposed NEM tariff because it conflicted with prior data provided by DESC. The PSCSC specifically stated:

[74] Graphic is of solar energy production on California Independent System Operator 2021 peak day (September 8, 2021), with overlays added by B. Powers. See: http://www.caiso.com/TodaysOutlook/Pages/supply.html.
[75] DEP Docket No. E-2, Sub 1280, *Order Approving Time-of-Use Rate Designs*, January 6, 2022, p. 2 (reference to Exhibit 1 – Duke Energy's September 30, 2021 TOU Period Technical Report – to DEP's application).
[76] Duke Energy Carolinas, LLC, Response to April 22, 2019 Order Requiring Additional Information Docket No. E-7, Sub 1146, May 23, 2019, Attachment 1 - Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study, February 2018.

> The Commission finds that the time-of-use ("TOU") periods in DESC's proposal are unreasonable because they do not align with the coincident system peak period identified in the Company's embedded cost of service study to allocate generation and transmission costs.[77]

The NCUC would be within its authority to make the same determination regarding Duke Energy's 6 pm – 9 pm on-peak summer TOU period proposed in the Application.

No underlying modeling data has been presented by Duke Energy to enable verification that the major shift in the summertime NEM on-peak period to 6 pm – 9 pm is justifiable. This major shift of the summer on-peak window works to the detriment of NEM customers. A compelling showing has been made by Duke Energy, in its 2018 "*Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study*," that the appropriate summer on-peak period should remain 2 pm – 8 pm.[78] The 2018 study is included as **Attachment D** to this report.

IX. The Incentive Payment Is Discriminatory

The $0.39/watt smart thermostat incentive payment outlined in the Application/MOU is being considered separately and has not yet been approved by the Commission.[79] If a home does not have electric heat, it cannot qualify for the incentive. About one-third of North Carolina households do not use electricity heating.[80] There is no information in the MOU on how the $0.39/watt incentive payment was determined. The current residential NEM solar incentive payment, expiring in 2022, began at $0.60/watt and was reduced to $0.40/watt because demand far exceeded the cap that had been set.[81]

Duke Energy is seeking approval of the thermostat incentive separately from the NEM tariffs in both North Carolina and South Carolina. The PSCSC approved Duke Energy's proposed

---

[77] Public Service Commission of South Carolina, *Docket No. 2020-229-E - Order No. 2021-391, Order Establishing Solar Choice Tariff for New Customers Beginning June 1, 2021*, May 29, 2021, Finding of Fact No. 7, p. 24.
[78] Duke Energy Carolinas, LLC, *Response to April 22, 2019 Order Requiring Additional Information Docket No. E-7, Sub 1146*, May 23, 2019, Attachment 1 - Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study, February 2018.
[79] NCUC Docket Nos. E-2 Sub 1287 & E-7 Sub 1261.
[80] Source: EIA, *North Carolina State Energy Profile*, November 18, 2021: https://www.eia.gov/state/print.php?sid=NC.
[81] NCUC, Docket Nos. E-2 Sub 1167 & E-7 Sub 1166, *Order Modifying Solar Rebate Program and Allowing Comments*, March 23, 2021, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=2ee6d528-2a5b-4a0c-bd18-e00f7150cc8e.

NEM tariffs in 2021[82] but rejected the incentive payment in 2022.[83] The MOU states that the incentive must be approved in both states to go into effect,[84] since it would be part of Duke Energy's energy efficiency/demand side management ("EE/DSM") program that spans both states. The approval of the thermostat incentive in North Carolina may be threatened unless the South Carolina incentive rejection is reversed.

The thermostat incentive would then not be available in either state to partially offset the less favorable economics of the proposed NEM tariffs relative to the existing NEM tariff. Therefore, the incentives that make the proposed tariff marginally comparable in value to the existing NEM tariff have been jeopardized. This undermines a core component of the terms of the settlement agreement and the terms of the NEM tariff proposed in the Application.

The Duke Energy NEM payback analysis assumes that NEM customers do not cover their entire annual demand with NEM solar and therefore have a monthly bill due to Duke Energy that offsets the $22/month or 28/month MMB.[85] In this scenario, the customer is relatively "blind" to the MMB, as eligible components of the customer's volumetric energy charges, the BFC, and riders completely cover the MMB.

For customers that are offsetting 100 percent of their annual energy consumption with NEM solar, the remainder of the MMB due beyond the BFC and riders would function as a de facto additional fixed monthly charge. It would have no effect on customers that undersize their rooftop solar systems sufficiently to assure they have a large enough balance to offset a $22/month MMB due to DEC or $28/month MMB due to DEP each month.[86]

The MMB also makes NEM solar less economically viable for lower-use customers who would generally require less solar capacity to meet their needs than the 8 kW to 10 kW system

---

[82] PSCSC, Docket Nos. 2020-264-E & 2020-265-E, Order No. 2021-390, Order Approving Stipulations, Approving Interim Riders, and Establishing Solar Choice Tariffs, May 30, 2021.
[83] PSCSC, Docket Nos. 2021-143-E & 2021-144-E, Commission Directive, January 13, 2022.
[84] MOU, at Ex. C, pdf pp. 15-16 ("Both the Rooftop Incentive and Winter BYOT Incentive must be approved by both the PSCSC and the NCUC in order to be offered by the Companies. DSM/energy efficiency programs costs are allocated across both jurisdictions in order for the program to be cost effective under traditional tests. Thus, the Incentives will not be available in South Carolina until both PSCSC and the NCUC approve.").
[85] **Attachment G**, Duke Energy's Response to the Public Staff's Data Request No. 1-1 (xls NEM bill comparison spreadsheet).
[86] Ibid.

size assumed by Duke Energy.[87] The negative economic impact of the MMB is proportionately greater on lower-usage customers with smaller solar arrays, as the MMB is a fixed value.[88] The MMB would function as a form of regressive tax in this case, just as fixed sales taxes have a proportionately higher impact on lower-income citizens.[89]

Due to the structure of the MMB, the payback period will be longer than projected by Duke Energy for customers who wish to offset 100 percent of their usage with solar, and for the smaller systems likely to be installed by lower-usage and low-income customers.

X. No Battery Storage Component to the Proposed NEM Tariff

The NC MOU states that by June 1, 2023 Duke Energy will file a program of additional "peak load reduction technologies that can be paired with solar," defined in the MOU as technologies that "lead to a reliable reduction of at least ~1 kW per hour during peak winter hours."[90]

Battery storage is rapidly becoming a standard element of NEM solar installations. Battery storage should be included in the initial incentive package to provide additional financial motivation for customers to store excess solar power for use during the high-priced peak windows when little or no solar power is being produced. The tariff is defective because it fails to contain provisions for fast-growing battery storage technology.

XI. No Lower- or Fixed-Income Customer Component to the Proposed NEM Tariff

The Petition only refers to a "solar program tailored to low-income customers as a potential future EE or demand response program."[91] An equitable, well-funded on-bill financing and/or on-bill repayment program, tied to the electric meter ("tariffed") and not to the

---

[87] **Attachment E**, Duke Energy's Response to Public Staff's Data Request No. 1-3(f), DEC 2019 xls spreadsheet 12 Oct 2021 ("Financial Forecast" tab); DEP 2019 xls spreadsheet 12 Oct 2021 ("Financial Forecast" tab).

[88] A DEC 5 kW NEM would produce half the solar power as a 10 kW NEM system on a monthly basis, but the MMB would remain a fixed $22/month for both systems. On a relative basis the fixed MMB would be twice as large, relative to the solar power produced, as it would be on the larger 10 kW system.

[89] $28/month for a customer with a typical bill of $100/month is 28 percent of the monthly bill. $28/month for a customer with a typical bill of $300/month is less than 10 percent of the monthly bill.

[90] Petition, pdf p. 55.

[91] Petition, pdf p. 46.

customer, would potentially lessen the equity barriers in the NEM settlement.[92] However, the MOU omits any such program.

XII. Need for Up-To-Date Value-of-Solar Assessment

H.B. 589 requires the Commission to conduct the investigation of the costs and benefits of NEM solar prior to establishing new NEM rates. Specifically, H.B. 589 as enacted states:

> § 62-126.4. Commission to establish net metering rates . . . (b) The rates shall be nondiscriminatory and established only after an investigation of the costs and benefits of customer-sited generation.

In conformance with the statute, the Commission should lead the investigation of the costs and benefits of NEM solar, not Duke Energy.

The National Renewable Energy Laboratory ("NREL") indicates that, as of 2019, NEM value-of-solar ("VOS") studies had been conducted in fifteen states.[93] The goals of NREL study reviewing VOS studies are ". . . to clarify the range of compensation structures used for DPV (distributed solar) across the country and . . . offer a summary of the variables that have been, or could be, considered in the development of a DPV cost-benefit valuation framework."[94]

A VOS study typically includes, at a minimum, assessing the NEM costs and benefits of: (1) energy, (2) generation capacity, (3) T&D losses, (4) T&D capacity, (5) environmental costs and benefits (such as avoided emissions), (6) ancillary services (such as voltage control), and (7) other (such as fuel hedging).[95] At the time of the NREL VOS survey in 2019, there was no standardized format for VOS evaluations. However, in 2020, the "*National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*" was developed to provide

[92] A successful equity on-bill financing program of this type is serving Hawaii IOU customers. See: https://www.eesi.org/articles/view/a-closer-look-at-hawaiis-innovative-financing-model-for-green-energy-investments.

[93] NREL, *Distributed Solar Photovoltaic Cost-Benefit Framework Study: Considerations and Resources for Oklahoma*, August 2019, p. 17 (sum of green states shown on US map): https://www.nrel.gov/docs/fy19osti/72166.pdf.

[94] Ibid, p. iv.

[95] Ibid, p. ix.

that standardization.[96] It is this Manual that should be utilized by the Commission to evaluate the costs and benefits of NEM solar.

Duke Energy purports that it has done an assessment of the costs and benefits of NEM solar, and that it presented the results to stakeholders in its Fast Track Working Group workshop process in the summer of 2021.[97] NC WARN was a participant in the NEM workshop process. Contrary to Duke Energy assertions, the NEM workshop process was not an in-depth dialogue on NEM tariff components with substantive involvement by stakeholders.[98] The material presented was not a balanced "investigation of the costs and benefits of customer-sited generation."[99] In the Fast Track workshops, Duke Energy presented summaries of its calculations and proposed NEM tariff elements as an instructor would present information to a room full of students with minimal background in the material being presented.

The apparent objective of the Fast Track workshop process was to get a majority of the participants to indicate support for Duke Energy's NEM tariff proposal via a survey Duke Energy conducted toward the end of the NEM workshop sessions. Duke Energy relies on the survey results to claim in its Application that "*This broad (stakeholder) support solidified the Companies' belief that the current energy landscape in North Carolina is ready and able to move forward with NEM reform*."[100] However, few of the stakeholders in the NEM workshops exhibited an understanding of (1) the relatively complex material being presented by Duke Energy on the proposed NEM tariff design or (2) what the alternatives might be.

Duke Energy also alludes incorrectly to "*broad stakeholder agreement under the MOU*" in its Application,[101] stating that:

> The rate structures of the NEM Tariffs not only reflect the principles arising from H.B. 589, H.B. 951, and significant work in the Rate Design Study, but also reflect recent broad stakeholder agreement under the MOU.

---

[96] T. Woolf, et al, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, National Energy Screening Project (Aug. 2020). Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

[97] Application, p. 7 (The Companies fulfilled G.S. § 62-126.4(b), as implemented by H.B. 589, by conducting an "investigation of the costs and benefits of customer-sited generation" through the Companies' Rate Design Study.)

[98] Ibid, p. 10 (The Companies engaged in productive and in-depth dialogue with stakeholders on NEM within the Rate Design Study over the course of seven workshops earlier this year.)

[99] N.C. Gen. Stat. § 62-126.4(b).

[100] Application, p. 11.

[101] Ibid, p. 2, p. 9, p. 10, p. 11, p. 12, and p. 20.

In fact, only four of the more than twenty stakeholders in the North Carolina process signed the MOU,[102] and these are the same set of stakeholders – with the addition of the Solar Energy Industries Association in North Carolina – that signed the Duke Energy NEM MOU in South Carolina.[103]

The NEM workshop process was not intended to be a collaborative dialogue of the costs and benefits of NEM solar. Substantive requests posed by knowledgeable participants, for example a request by NC WARN to review the Duke Energy modeling inputs that would support shifting the NEM summertime on-peak window from 2 pm – 8 pm to 6 pm – 9 pm, went unanswered. That question continues to go unanswered in the NEM proceeding despite repeated data requests by NC WARN seeking this same information.

It is not unusual for state utility commissions to lead investigations into the costs and benefits of NEM solar. For example, the CPUC has led the two NEM successor tariff investigations, in 2013 and 2021, conducted in California.[104,105] The Commission should lead the investigation into the costs and benefits of NEM solar in this proceeding

XIII. Conclusions

North Carolina has little NEM solar, 187 MW out of 7,811 MW total installed capacity, despite being the fourth state in the nation in terms of solar capacity.[106,107] Virtually all North Carolina solar capacity, nearly 98 percent, is utility-scale solar. The reduction in the economic value of residential NEM solar under the proposed NEM tariff would perpetuate this imbalance.

---

[102] Ibid, p. 10 ("Participants in these workshops included over 20 organizations . . . .") and pdf p. 45 [North Carolina Sustainable Energy Association; Southern Environmental Law Center on behalf of Vote Solar and Southern Alliance for Clean Energy; Sunrun, Inc.; and Solar Energy Industries Association (collectively, the ("Clean Energy Advocates")].

[103] Public Service Commission of South Carolina, Docket No. 2020-264-E and 2020-265-E — Order No. 2021-390, *Order Approving Stipulations, Approving Interim Riders, and Establishing Solar Choice Tariffs*, May 30, 2021, p. 11 (. . . the Companies explained the Memorandum of Understanding ("MOU") executed on September 16, 2020, by and among the (Duke Energy SC) Companies; NCSEA; Sunrun Inc.; Vote Solar; and SELC on behalf of SCCL, Southern Alliance and Upstate Forever (the "MOU"), which formed the foundation for the Residential Stipulation.].

[104] CPUC, *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared by Energy+Environmental Economics (E3), October 2013.

[105] CPUC, *Net-Energy Metering 2.0 Lookback Study*, prepared by Verdant Associates, LLC, January 21, 2021.

[106] EIA 2020, *North Carolina Electricity Profile*, November 4, 2021, Table 11.

[107] Solar Electric Industries Association, *State Solar Spotlight – North Carolina*, March 10, 2022: https://www.seia.org/sites/default/files/2022-03/North%20Carolina%20Solar-Factsheet-2021-YearinReview.pdf.

There is no cost-shift with the existing NEM tariff when avoided T&D benefits are accurately quantified. At a minimum Duke Energy should maintain the existing NEM tariff structure, with a 2 pm – 8 pm summer on-peak period, and include incentives to encourage customers to add battery storage to their NEM systems.

Finally, an omission in the Petition/settlement agreement is a financing element that includes tariffed on-bill financing to assure that lower-income customers have equitable access to NEM solar.

Attachment B

Deployment of NEM Solar Allows Duke Energy to Eliminate New Transmission That Would Otherwise Be Built, an Analysis by Mr. Powers

Attachment B

Deployment of NEM Solar Allows Duke Energy to Eliminate New Transmission That Would Otherwise Be Built

Pacific Gas & Electric (PG&E) Example

March 28, 2022, Bill Powers, P.E.

NEM solar eliminates expansion of the transmission and distribution ("T&D") system that would otherwise be necessary to accommodate load growth and congestion. These are also known as "grid reliability" projects. Duke Energy's avoided T&D calculation assumes NEM solar is only deferring T&D expansion that will inevitably occur, and not eliminating it.[1] The value of NEM for eliminating capital investment in T&D expansion is substantially greater than the avoided T&D value of NEM that Duke Energy assumes in its NEM cost-shift analysis.[2] The avoided cost of high voltage transmission alone would be about $935 per year per typical 9 kW DEC or DEP system. This is substantially greater than the alleged DEC NEM cost shift of $363 to $372 per year, and the DEP NEM cost shift of $708 per year, identified by Duke Energy.[3]

California data is used to calculate the transmission elimination benefit of NEM because the NEM solar deployments that eliminated the new transmission that would otherwise have been built in PG&E territory actually occurred. The calculated benefit is not based on hypothetical, modeled scenario. The evaluation of an actual scenario is possible due to the tremendous amount of NEM solar that has been installed in California. The state has over

[1] **Attachment J**, Duke Energy's Response to NC WARN's Data Request No. 4-4, which requested supporting documentation for the avoided electric T&D values, is "work in progress".
[2] **Attachment H**, Duke Energy's Response to NC WARN's Data Request No. 1-11. 2022 DEC-NC RE System Benefits, Avoided Electric T&D = $247; 2022 DEC-NC RS System Benefits, Avoided Electric T&D = $196; 2022 DEP-NC RES System Benefits, Avoided Electric T&D = $127.
[3] Ibid.

12,000 MW of NEM solar, or about 36 percent of the installed NEM solar capacity in the country.[4] High voltage (> 200 kV) transmission planning in California is conducted by the California Independent System Operator ("CAISO"). In 2018 CAISO identified the unexpected growth in NEM solar in PG&E service territory as a primary reason CAISO cancelled $2.6 billion in proposed transmission projects in PG&E territory. This determination was made by CAISO at the end of a three-year review of PG&E transmission expansion proposals.[5,6]

CAISO indicates that a perceptible impact of NEM solar on peak loads was first observed in 2015 by the California Energy Commission ("CEC").[7] CAISO utilizes the CEC load forecasts in its transmission planning process. A projected increase in peak load is a principal justification for new transmission projects.[8] In the three-year 2015-2017 time period, 1,685 MW of NEM

---

[4] PV Magazine, *US added 5.4GW of small-scale PV last year*, March 1, 2022: https://pv-magazine-usa.com/2022/03/01/us-added-5-4gw-of-small-scale-pv-last-year/. California ÷ US total = 12,000 MW ÷ ~33,000 MW (as of end of 2021) = 0.36 (36 percent).

[5] CAISO press release, *Board approves 2017-18 Transmission Plan, CRR rule changes* (Mar. 23, 2018), available at http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf. "The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation."

[6] CAISO, *2017-2018 ISO Transmission Plan* (Mar. 22, 2018) pp. 2-3, available at http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf. "In this third year of a comprehensive review of previously-approved projects in the PG&E service territory, the ISO built on study efforts in previous cycles and not only identified projects that were no longer needed, but also explored re-scoping a significant number of projects to better reflect evolving needs. As a result of the review, 18 projects are recommended to be canceled, and major scope changes have been identified for 21 other projects, paring over $2.6 billion from the ISO transmission capital program estimated costs. Seven other projects will continue to be on hold pending reassessment in future cycles."

[7] Ibid, p. 17. "The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available. This is an issue that has been progressing through subsequent IEPR processes, having first been noted in the CEC's 2015 effort."

[8] R.14-10-003 (Integrated Distributed Energy Resources), *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (Oct. 7, 2019), p. 47. "The utilities and the CAISO often categorize transmission projects based on the principal reason for the project, such as:

- Load growth – serving peak demand
- Reliability – addressing N-1 or N-1-1 contingencies in high load hours
- Economic – relieving congestion, which typically occurs in high-demand hours

solar was added in PG&E territory.[9] This NEM growth rate was substantially more rapid than assumed by CAISO.[10] The CEC forecast of NEM solar growth in PG&E territory for the 2015-2017 period was approximately 230 MW.[11,12] This is about 1,440 MW less than the actual addition of 1,685 MW of NEM solar in PG&E territory in the 2015-2017 period. The amount of NEM solar installed in PG&E territory at the end of 2014 was also about 100 MW higher than forecast for 2014 by the CEC in November 2013.[13] The total net increase in NEM solar in PG&E territory in 2015-2017 above the CEC forecast was approximately 1,540 MW.[14]

The amount of energy efficiency ("EE") peak load reduction targeted for PG&E territory in 2015-2017 is also known. PG&E's goals for EE-related peak load reduction, as defined in the

---

- Policy-driven – to meet RPS needs based on MWh goals

However, the transmission system is a network, and an addition that is made principally for one reason (for example, reliability) also will increase the system capacity to serve load growth, as a secondary benefit. In addition, the first three of the above types of transmission projects (peak load growth, reliability, and economics) are directly or closely tied to peak demands on the grid, and all types of additions to the networked grid [including capacity to access new Renewable Portfolio Standard (aka "renewable energy") resources] may contribute to serving peak demands. Further, renewable generation from DERs, or reduced load from demand response or energy efficiency measures, contribute equally with (renewable energy) generation (which may require new transmission) to meeting the state's long-term carbon reduction goals. As a result, the long-term avoided or deferred transmission costs associated with DERs should be calculated considering all investments in transmission."

[9] California Distributed Generation Statistics, Stats & Charts, PG&E, accessed June 18, 2021: https://www.californiadgstats.ca.gov/. PG&E NEM solar, December 31, 2014 = 1,160 MW; December 31, 2017 = 2,845 MW. NEM solar increase, 2015-2017 = 1,685 MW.

[10] CAISO, *2017-2018 ISO Transmission Plan* (Mar. 22, 2018), p. 16. "These trends, including higher than previously expected levels of behind-the-meter solar generation, are producing new and more complex operating paradigms for which the ISO must consider in planning the grid."

[11] CPUC, NEM 2.0 Lookback Study, prepared by Verdant Associates, January 21, 2021, Table 1-1, p. 4. PG&E residential: average system size 5.9 kW_{DC}. Assume 85% DC-to-AC conversion efficiency, therefore 5.9 kW_{DC} = 5.015 kW_{AC}. Annual production = 9,696 kWh. Therefore unit annual production = 9,696 kWh ÷ 5.015 kW_{AC} = 1,933 kWh/kW_{AC}.

[12] California Energy Commission, Final California Energy Demand Update (CEDU) 2013 Forecast, PG&E Form 1-2-Mid, "PV", xls spreadsheet, November 2013. 2014 PV = 2,046 GWh; 2017 PV = 2,385 GWh. 2014 PV forecast in MW: 2,046,000 MWh ÷ 1,933 MWh/MW_{AC} = 1,058 MW. 2017 PV forecast in MW: 2,485,000 MWh ÷ 1,933 MWh/MW_{AC} = 1,286 MW. CEC forecast increase in NEM PV in PG&E, 2015-2017 = 1,286 MW – 1,058 MW = 228 MW.

[13] California Distributed Generation Statistics, Stats & Charts, accessed July 13, 2021. PG&E NEM solar total at end of 2014 = 1,157 MW. See: https://www.californiadgstats.ca.gov/charts/. Net difference in PG&E NEM solar at end of 2014 compared to 2013 CEDU forecast for PG&E = 1,157 MW – 1,058 MW = +99 MW.

[14] 1,440 MW + 100 MW = 1,540 MW.

relevant California Public Utilities Commission ("CPUC") decision, were 154 MW for 2015, 226 MW for 2016, and 193 MW for 2017, a total of 573 MW for the three-year period.[15]

Peak load in California typically occurs in mid- to late afternoon, when a NEM solar system is no longer producing at maximum capacity. For example, over the last five summers (2017 – 2021) in California, the maximum annual peak demand occurred between 3:57 pm and 5:50 pm.[16] As a result, what must be calculated is the percentage of NEM solar capacity that is actually contributing to peak load reduction. This is known as the "peak capacity allocation factor," or PCAF.[17] In PG&E territory, the PCAF is approximately 35 percent.[18,19] The portion of the NEM solar added in 2015-2017 contributing to peak load reduction is 1,540 MW x 0.35, or about 540 MW. Based on the approximately equal 2015-2017 peak load reductions associated with new EE and NEM solar in PG&E territory, about one-half of the cancelled PG&E transmission project savings – $1.3 billion – are attributable to NEM solar.

The conversion of PG&E transmission capital cost expenditures that were avoided by NEM solar into an annualized cost allows calculation of transmission costs avoided by the

---

[15] D.14-10-046, *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs And Budgets* (Oct. 16, 2014), Figure 1, p. 10 (2015 peak savings goal = 154.4 MW); D.15-10-028, *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*, October 22, 2015, Table 2, p. 9 (2016 peak savings goal = 226 MW, 2017 peak savings goal = 193 MW). Total = 154 MW + 226 MW + 193 MW = 573 MW.

[16] CAISO, *California ISO Peak Load History 1998 through 2021*, January 2022: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

[17] CPUC, Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update Integrated Distributed Energy Resources Rulemaking (R.14-10-003) (Apr. 16, 2020), p. 42. "Peak Capacity Allocation Factor (PCAF) Method. Peak reduction is the weighted average resource performance across hours in the peak period. The weights are relative to the project area demand in excess of a "peak threshold." The higher the demand, the higher the weight assigned to the hour to approximate higher need for capacity in the higher demand hours."

[18] CPUC, *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, prepared by E3, June 24, 2020: PG&E PCAF, NEM solar-only = 35%.

[19] The PCAF for DEC and DEP customers in North Carolina was estimated at 42% in 2013. See: Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 2013, Table 7 ("Solar Capacity as % of Nameplate"), p. 12.

addition of each new NEM solar project.[20] As shown in Table 4, assuming an average NEM solar system capacity of 6 kW_{AC}, each NEM solar system installed in PG&E territory in the 2015-2017 period avoided approximately $620/yr in new transmission cost.

Table 4. Calculation of PG&E avoided transmission expenditure value of NEM solar

Element	Calculation	Value
PG&E capital transmission costs avoided by NEM solar, 2018	--	$2.6 billion
Annualized cost of avoided new PG&E transmission[21]	($2.6 billion ÷ $1.883 billion) x $254 million/yr = $350 million/yr	$350 million/yr
NEM solar added in PG&E territory, 2015-2017	--	1,540 MW
Avoided transmission capital cost and annual costs attributable to NEM solar	50% attributable to NEM solar, 50% attributable to EE	$1.3 billion capital, $175 million/yr annual
Number of residential NEM solar projects at 6 kW each, 2015-2017	1,685,000 kW ÷ 6 kW/project = 281,000 projects	281,000 projects
Annual value of avoided PG&E transmission per 6 kW residential NEM project	$175 million/yr ÷ 281,000 projects = $623/yr/project	$623/yr/project

The calculated annual transmission savings of about $620/yr/system is for solar-only 6 kW_{ac} NEM systems, a typical capacity in PG&E territory for the 2015-2017 time period evaluated. In contrast, Duke Energy evaluated NEM systems in DEC and DEP service territories that average approximately 9 kW_{ac} in capacity.[22] If a 9 kW_{ac} solar-only system is assumed, the annual avoided transmission savings of that system would be approximately $935/yr/system.[23]

[20] The ratio of capital cost to annualized cost in the SDG&E's 500 kV Sunrise Powerlink (SPL) transmission line application is used as the point of reference to estimate the annual cost of $2.6 billion in new transmission capacity in PG&E territory. SPL capital cost = $1.883 billion. SPL annualized cost over 40 years = $254 million/yr.

[21] The annualized PG&E cost is extrapolated from the $254 million/yr annualized cost of SPL based on a SPL capital cost of $1.883 billion.

[22] **Attachment N**, Duke Energy's Response to the Public Staff's Data Request No. 1-2 (xls spreadsheet). Average capacity of DEC NEM systems = 9.2 kW_{ac}. Average capacity of DEC NEM systems = 9.1 kW_{ac}.

[23] 9 kW_{ac}/6 kW_{ac} x $623/yr/system = $935/ yr/system.

It is now common for new residential NEM systems to include battery storage. Battery storage doubles the NEM system PCAF, from 35 percent to 70 percent.[24] This doubles the amount of NEM capacity available for peak load reduction, and increases the avoided transmission cost benefit of a NEM solar plus battery storage system.

The CPUC, in its April 2020 decision approving the 2020 Avoided Cost Calculator inputs, acknowledged qualitatively that NEM solar played a role in avoiding transmission costs but declined to monetize that avoided cost.[25] Monetizing the avoided cost of grid reliability transmission projects that are cancelled because of NEM solar, assuming a benefit of approximately $935 per year per NEM solar system in DEC and DEP service territories, would – by itself –eliminate the alleged residential NEM cost-shift.

[24] CPUC, *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, prepared by E3, June 24, 2020: PG&E PCAF, solar + battery storage = 70%.

[25] D.20-04-010, *2020 Policy Updates to the Avoided Cost Calculator*, April 16, 2020, p. 60. "We acknowledge that distributed energy resources avoid transmission costs but, at this time, the record in this proceeding provides no reasonable alternate method of determining unspecified avoided transmission costs."

Attachment C

Substitution of Residential NEM Solar for New Transmission Built to Serve Remote, Utility-Scale Solar in North Carolina Could Add $1,600/yr in Avoided Transmission Value to these NEM Systems, an Analysis by Mr. Powers

Attachment C

Substitution of Residential NEM Solar for New Transmission Built to Serve Remote, Utility-Scale Solar in North Carolina Could Add $1,600/yr in Avoided Transmission Value to these NEM Systems

San Diego Gas & Electric (SDG&E) Example

March 28, 2022, Bill Powers, P.E.

NEM solar can eliminate expansion of the transmission and distribution ("T&D") system that would otherwise be necessary to delivery remote, utility-scale renewable energy to major demand centers. In North Carolina, utility-scale solar development has been centered in the southeastern part of the state, while the major demand centers (Charlotte, Greensboro/ Winston-Salem, Raleigh-Durham) are located in central and western North Carolina. Duke Energy projects that DEC and DEP will collectively add 2,652 MW of utility-scale solar between 2021 and 2026.[1] If utility-scale solar continues to be concentrated in eastern and southeastern North Carolina, substantial transmission expansion will likely be necessary to deliver this solar power to North Carolina demand centers.

The value of NEM solar can be calculated data available in other states, specifically California, where transmission lines have been purpose-built to transport utility-scale solar and wind power to demand centers and cost of the transmission line and amount of renewable energy being transmitted are known with precision. The example evaluated in this attachment is SDG&E's 500 kV Sunrise Powerlink (SPL) transmission line. SPL is one of the three largest California Independent System Operator-approved transmission lines to come online in the last

[1] **Attachment K**, Duke Energy's Responses to NC WARN's Data Request Nos. 1-5 (DEC) and 1-10 (DEP).

decade.[2] This controversial transmission line was approved in December 2008, with the assigned commissioner voting against approval of the line.[3] The SPL application had been initially denied by the assigned administrative law judge (ALJ), who observed at the end of a two-year proceeding that the local generation alternative was superior to SPL for cost and reliability reasons.[4] The ALJ had determined there was no near-term reliability justification for SPL, and no regulatory framework (at the time) to mandate the line be dedicated to supplying renewable power.

SDG&E committed to interconnecting 1,000 MW of renewable power to the 120-mile long SPL.[5] As of 2020, eight years after SPL came online in 2012, there was approximately 1,000 MW of solar and 265 MW of wind power connected to SPL.[6] The annualized cost of the $1.883 billion SPL, over 40 years, is $254 million per year.[7]

---

[2] CPUC, *Utility Costs and Affordability of the Grid of the Future* (Feb. 2021), Table 10, p. 38.

[3] D.08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (Dec. 18, 2008), pdf pp. 305-311, Dissent of Commissioner Dian M. Grueneich (the assigned commissioner to the proceeding).

[4] A.06-08-010, *(Proposed) Decision Denying a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (Oct. 31, 2008), p. 4. "The record shows, on balance, that all of the transmission proposals likely would provide additional reliability to SDG&E's service area. However, SDG&E's service area will not experience a reliability need or "shortfall" until 2014, and the shortfall may be met more economically and more reliably with generation-based alternatives."

[5] Sempra press release, *SDG&E's Sunrise Powerlink Reaches 1,000 Megawatt Renewable Energy Goal* (Dec. 18, 2014), available at https://www.sempra.com/newsroom/press-releases/sdges-sunrise-powerlink-reaches-1000-megawatt-renewable-energy-goal.

[6] *SDG&E Final 2019 RPS Procurement Plan* (Jan. 29, 2020), Appendix 1 p. 15 & p. 18, available at https://www.sdge.com/sites/default/files/regulatory/2019_Final%20RPS%20Plan%20Public%20Version.pdf, 999 MW solar; + 265 MW Ocotillo Wind: https://patternenergy.com/learn/portfolio/ocotillo-wind.

[7] CPUC D.08-12-058, Finding of Fact 42, p. 289 (capital cost = $1.883 billion). Ratio of final $1.883 billion capital cost of Sunrise Powerlink to original $1.265 billion capital cost multiplied by original annualized cost in A.06-08-010 (SDG&E, *Application for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project*, August 4, 2006, p. V-11), plus annual O&M: [($1.883 billion/$1.265 billion) x $164 million/yr] + $10 million/yr O&M = $244 million/yr + $10 million/yr O&M = $254 million/yr.

The avoided transmission value of residential NEM solar, compared to the amortized capital cost of SPL to deliver the same amount of renewable energy, is approximately $1,600 per 9 kW_{AC} residential NEM system as shown in Table 1.

Table 1. Calculation of avoided Sunrise Powerlink transmission expenditure value of NEM solar

Element	Calculation	Value
Capital cost of Sunrise Powerlink, 2008	--	$1.883 billion
Annualized cost of Sunrise Powerlink	40-year amortization of capital cost, plus $10 million/yr O&M expense	$254 million/yr
Actual renewables capacity connected to Sunrise Powerlink	999 MW solar, 265 MW wind	1,264 MW
Required number of residential NEM solar projects at 9 kW/each to achieve equivalent peak output	1,264,000 kW_{AC} ÷ 9 kW_{AC}/project	140,000 projects
Total NEM projects needed to account for lower NEM solar annual energy production compared to utility-scale solar[8]	0.27 (utility-scale capacity factor) ÷ 0.22 (NEM solar capacity factor) = 1.23	172,000 projects
Total NEM projects needed, adjusted for avoided T&D losses[9]	-7.10 percent	160,000 projects
Annual value of avoided SDG&E transmission per residential NEM project	$254 million/yr ÷ 160,000 projects	$1,588/yr/project

[8] ICSREE 2020, *Capacity factors of solar photovolltaic energy facilities in California, annual mean and variability*, 2020. Table 1, p. 2 (2018 CF data for Imperial Valley solar facilities). See: https://www.e3s-conferences.org/articles/e3sconf/pdf/2020/41/e3sconf_icsree2020_02004.pdf; NREL, PVWatts Calculator, Los Angeles, 0.22 alternating current capacity factor assuming 15 percent direct current-alternating current system losses: https://pvwatts.nrel.gov/.

[9] CPUC, *2020 Distributed Energy Resources Avoided Cost Calculator Documentation*, prepared by E3, June 24, 2020, p. 70.

Attachment D

Duke Energy Carolinas Time-of-Use and Seasonal Pricing Study (2018)

Duke Energy Carolinas
Time-of-Use and Seasonal Pricing Study
February 2018

Table of Contents

DEC Time-of-Use and Seasonal Pricing Study

Project Description

This study is undertaken to evaluate a time-of-use ("TOU") rate design that is consistent with current cost causation and would better incent load shifting that is reflective of current marginal cost of service. Changes to system load occurring over the past several years indicate fundamental changes to customer consumption on a total system basis due to improved efficiencies in electrical use, increased deployment of solar generation to reduce overall consumption during certain hours, and the advent of new technologies such as electric vehicle charging. DEC's current TOU rate design structures have not been updated in several years to address these fundamental changes. This analysis considers forecasted system load data to minimize bias due to unusual weather or other historic conditions that influence usage on a peak day. The review also considers variations in forecasted marginal energy cost and loss of load probabilities to understand their influence.

Many factors, beyond just the cost of service, should be considered in an effective TOU rate design including:

1. Understandability – the design needs to provide customers with clear price signals that incent the proper behavior. With greater rate design complexity, customers might not clearly recognize the best load response.
2. Practicality – peak price periods must recognize that all activities can't be shifted to the middle of the night when costs are typically at their lowest. The design needs to recognize that under a proper design, even a shift of several hours can result in a lower cost of service, benefitting all ratepayers.
3. Financial management – while it may be appealing to offer low rates during the Spring and Fall when the utility has a lower cost of service, it is unlikely that this would incent shifting of load from another season and wouldn't align with customer income which is constant for most customers from month to month thereby potentially creating hardship in months with higher rates.
4. Cost causation alignment – an optimal design includes customer, demand and energy rates to align with cost of service. The use of a demand rate limits the utility's ability to send substantial price signals with energy rates if more than an on- and off-peak period is included in the design. This is especially true today since marginal energy cost is currently relatively flat during all hours other than system peak days. Energy rate differentials offer the most easily understood tool to incent load shifting because the customer can clearly identify the rate differential as the potential savings realized by delaying a load to a later period.
5. Alignment with metering and billing systems – with the deployment of AMI metering, more sophisticated rate designs are now possible, but may be limited by a meter's capability to display the desired TOU periods due to register constraints. Also, the present CBIS billing system has limited flexibility to add new rating periods at a reasonable price

and timeframe if they aren't presently being billed in another schedule. Customer Connect is expected to aid in the Company's ability to bill innovative designs.

6. Technology and Education - A rate design's ability to incent load shifting is greatly enhanced if technology is available to help customers understand the financial impact. This is especially true for demand billing. Improved customer understanding can be accomplished with real time or next day access to meter data or technology to automatically change HVAC settings or de-energize equipment during high cost hours. A simple time clock is an excellent tool to shift load under a fixed period design, but more sophisticated tools are expected in the future.

System Load Shape – Seasonal Differentiation

Although utility load characteristics change seasonally, monthly adjustments to TOU hours are often confusing to customers who overlook the need to change their behavior or technology settings. A two-season design minimizes this confusion while continuing to recognize changes in the utility's cost of service. Even though DEC is now a winter planning utility from an Integrated Resource Planning perspective, forecasted load data indicates that DEC has a predominate summer peak. The winter emphasis is also supported by loss of load probability data that highlights a greater concern with serving load in winter months. This winter emphasis is expected to be a greater concern with increased deployment of behind the meter solar generation which will reduce load served during daylight hours. A review of the 2019-2028 forecasted system load data indicates that DEC exhibits two distinct load shapes – a winter load shape that peaks in the early morning and a summer load shape that peaks in the late afternoon. DEC clearly exhibits a morning peak in the months November through March and an afternoon peak in the months of May through September. April and October both have a less predominate late day peak tending to suggest they be included in the summer period, but are recommended for inclusion in the winter month to not dilute the summer price emphasis. The hour of peak for each month in the forecasted period is shown in Table 1 below.

Month	Maximum Load	Peak Hour
January	14,594	HE 800
February	13,254	HE 800
March	11,158	HE 800
April	11,039	HE 2100
May	12,536	HE 1700
June	15,256	HE 1700
July	**16,130**	HE 1700
August	16,023	HE 1700
September	12,885	HE 1700
October	10,629	HE 2000
November	12,575	HE 800
December	13,263	HE 800

Table 1: 2019-2028 Average Maximum Monthly Peak Demand (Source: Gerald Morgan for NC avoided cost proceeding)

The load analysis indicates that seasonal months should be defined as Summer (May through September) and Winter (October through April).

System Load Shape – Summer Months (May through September)

The forecasted load data is also informative with respect to the hourly load shape. Figure 1, below, provides the average hourly weekday system load for the summer months of May through September.

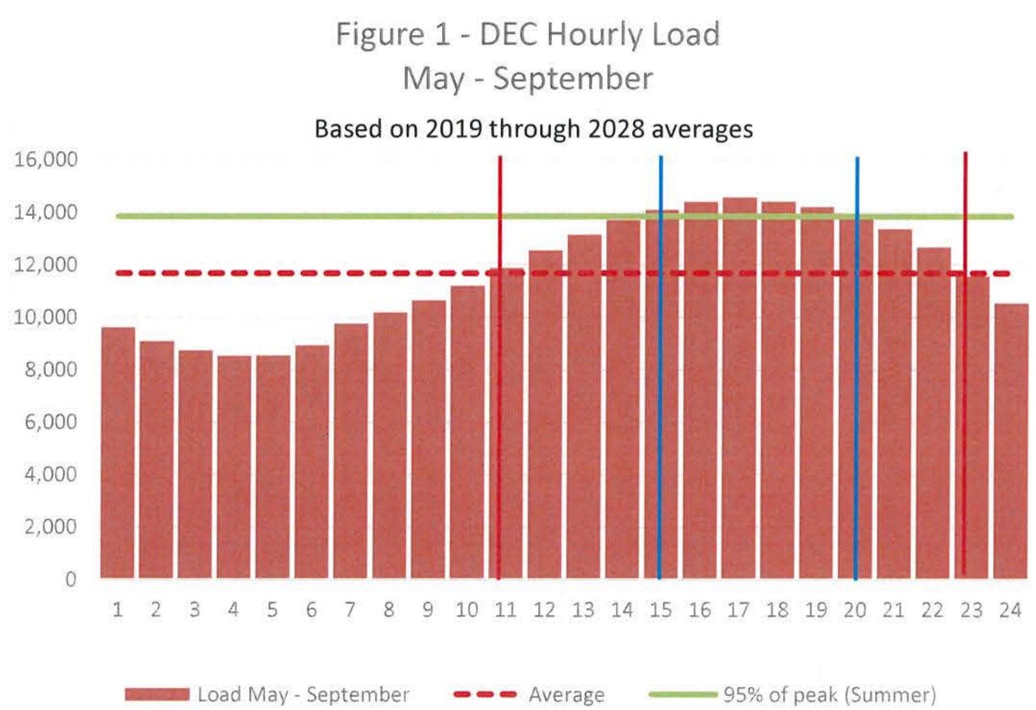


Figure 1 indicates higher than average load during the hours 10 a.m. to 11 p.m. This is deemed to be too long of a duration to expect customers to successfully defer consumption. *A more focused on-peak period would include just the hours with load within 95% of the peak hour or the hours from 2 p.m. to 8 p.m.* System load begins to decline after 8 p.m.; therefore, load rebound concerns shouldn't be significant unless TOU adoption rates exceed expectations. Electric Vehicle charging could influence load during off-peak hours in the future, but the rate design should be modified at that time if the peak can't adequately be controlled with a targeted demand response program for EV charging. The advantage of the 95% criteria is that it results in fewer hours with high rates thereby allowing a greater price differential between on- and off-peak and requiring fewer hours of load response to gain an economic advantage. An additional advantage of the 95% criteria is a reduced likelihood of the peak merely being shifted to a surrounding hour.

System Load Shape – Winter Months (October through April)

The forecasted load data is also informative with respect to the hourly load shape. Figure 2, below, provides the average hourly weekday system load for the winter months of October through April.

Figure 2 - DEC Hourly Load
October - April
Based on 2019 through 2028 averages

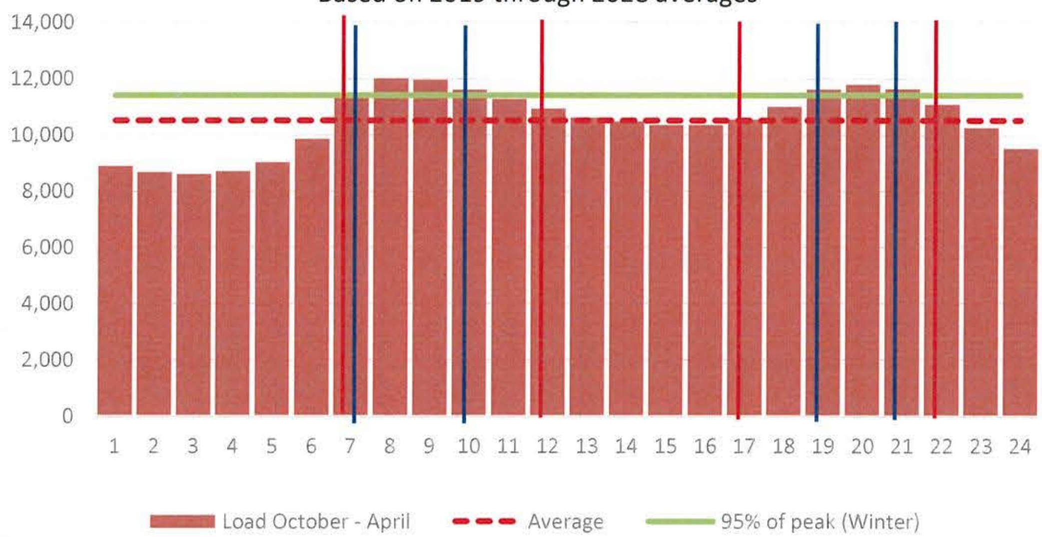


Figure 2 indicates higher than average load during the hours 6 a.m. to noon plus 5 p.m. to 10 p.m. Historically, DEC TOU designs haven't reflected an evening peak in the winter months but the magnitude of the morning and evening peaks have narrowed in recent years. An eleven (11) hour period is deemed to be too long of a duration to expect customers to defer consumption. *A more focused on-peak period would include just the hours with load within 95% of the peak hour or the hours from 6 a.m. to 10 a.m. plus 6 p.m. to 9 p.m.* System load begins to decline after 10 a.m. plus increased penetration of solar generation should cause greater declines in usage in the future making later usage a smaller concern. Load after 9 p.m. also declines minimizing rebound concerns. As noted above, electric vehicle charging in the evening hours continues to be a future concern during both the summer and winter periods if demand response programs are unsuccessful in avoiding system peak hours. The hours can be reconsidered in the future if either solar or EV charging impacts on system load are more significant than expected. The advantage of the 95% criteria is that it results in fewer hours with high rates thereby allowing a greater price differential between on- and off-peak and requiring fewer hours of load response to gain an economic advantage. An additional advantage of the 95% criteria is a reduced likelihood of the peak merely being shifted to a surrounding hour.

OFFICIAL COPY
Mar 29 2022

Loss of Load Expectations - Seasonal Price Emphasis

Loss of load expectation ("LOLE") was reviewed to assess how the seasonal peaks influence resource additions. Table 2, below, shows the hourly LOLE data by month at current system load.

Table 2 - Duke Energy Carolinas - Loss of Load Hours

	No Solar (*Only months with LOLE are shown*)									Percent of Season	
Month/ Hour	1	2	3	6	7	8	12	Winter	Summer	Winter	Summer
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	3%	0%	0%	0%	0%	0%	0%	4%	0%	11%	0%
8	9%	1%	1%	0%	0%	0%	0%	11%	0%	34%	0%
9	6%	1%	2%	0%	0%	0%	0%	9%	0%	26%	0%
10	2%	0%	1%	0%	0%	0%	0%	3%	0%	9%	0%
11	1%	0%	0%	0%	0%	0%	0%	1%	0%	3%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	1%	1%	0%	0%	2%	0%	3%
15	0%	0%	0%	0%	4%	5%	0%	0%	9%	0%	14%
16	0%	0%	0%	0%	10%	9%	0%	0%	19%	0%	28%
17	0%	0%	0%	0%	11%	10%	0%	0%	21%	0%	31%
18	0%	0%	0%	0%	6%	6%	0%	0%	12%	1%	17%
19	2%	0%	0%	0%	2%	2%	0%	2%	4%	6%	6%
20	2%	0%	0%	0%	0%	0%	0%	2%	1%	5%	1%
21	1%	0%	0%	0%	0%	0%	0%	1%	0%	4%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	26.74%	**2.29%**	**3.95%**	**0.18%**	**33.39%**	**33.04%**	**0.40%**	**33.38%**	**66.62%**	**100%**	**100%**

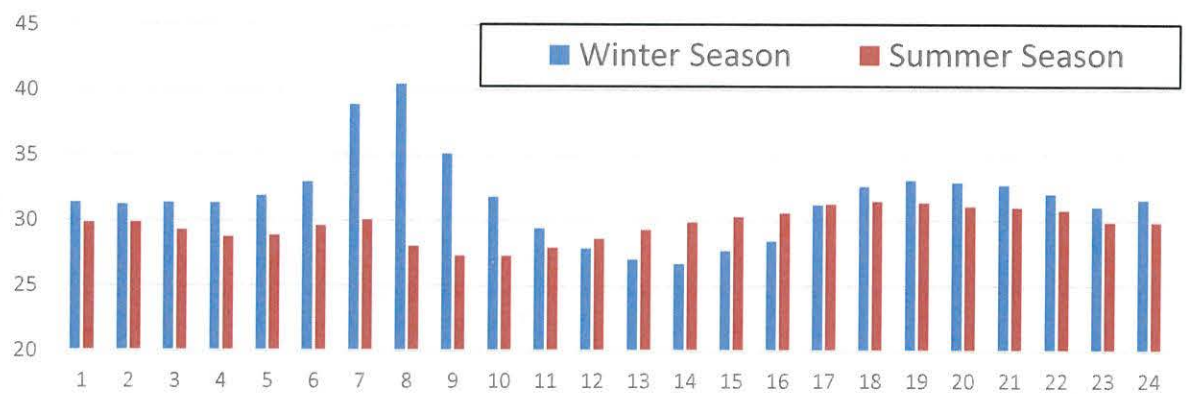
Source: 2019 Astrape Study

LOLE considers the likelihood that there will be unserved energy in any given hour due to inadequate generation supply. The above LOLE data was found in the Astrape study used to assess the influence of future solar generation on Company operations. The table reflects LOLE at current DEC system load. The Astrape data provides insight regarding the influence on LOLE with increased deployment of solar generation caused by the Competitive Procurement of Renewable Energy ("CPRE"). From a capacity perspective the winter months of December through March are the most critical for ensuring adequate generation capacity (84% of annual hours) is available to serve load and therefore should reflect a pricing emphasis. *From a LOLE perspective, the hours from 6:00 a.m. to 11:00 a.m. in the winter months and the hours from 1 p.m. to 8:00 p.m. in the summer months are most critical from the perspective of the utility's ability to serve its load requirement.* These hours align with the system load analysis.

Marginal Cost Assessment

Marginal energy and capacity cost relationships were reviewed to aid in establishing pricing/rate differentials in the TOU rate design and to determine if marginal energy cost indicates an on-peak period where higher energy costs are expected. Forecasted lambda trends indicate a definite narrowing of costs with steadily diminishing differences during the hours of the day, but fails to identify a distinct difference in pricing during specific hours. Average hourly marginal energy cost during the forecast period 2018-2023 is shown in Figure 3, below:

Figure 3 - DEC Average Hourly Marginal Energy Cost ($/MWHr) 2018-2023



Forecast data was next reviewed by rating period to assess price differentials in table 3, below:

Table 3 – DEC Average Marginal Energy Cost (2018-2023) by rating period			
Weekdays Only	Hours	On-peak Hours	Off-peak Hours
Summer	*2 pm to 8 pm*	31.01	29.22
Winter	*6 am to 10 am plus 6 pm to 9 pm*	35.00	30.34
Winter Morning		*36.56*	
Winter Evening		*32.92*	

Marginal energy data indicates a minimal difference between on-peak and off-peak cost, especially in the summer period. There is a greater difference in the winter months, particularly in the morning hours. This difference suggest that a higher on-peak rate in the winter morning than offered in the evening on-peak period. This adds complexity to the rate design and could cause customer confusion in understanding the impact of shifting decisions. This confusion could be minimized if coupled with technology that clearly identifies price differences. *From a marginal cost perspective alone, there would only be 0.35¢/kWh difference between morning and evening on-peak rates; therefore, it would be necessary to include some demand-related cost in the on-peak energy rate to create an incentive for shifting load off-peak.* LOLE data suggests that only 16% of winter LOLE occurs during the evening hours suggesting that recovery of demand-related costs should emphasize winter morning rates. There was also little difference in summer and winter off-peak marginal energy cost suggesting that a single annual off-peak energy rate is supportable.

Conclusion

The following TOU rate structure is recommended:

TOU Seasons	**Summer Period**	**Winter Period**
Calendar Months	May through September	October through April
Weekday On-peak hours	2:00 p.m. to 8:00 p.m.	6:00 a.m. to 10 a.m. plus 6:00 p.m. to 9:00 p.m
Off-peak Hours	All weekends and all other weekday hours, excluding holidays	
Off-peak Holidays	New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving's Day and the following Friday, and Christmas Day	

Off-peak energy rates should exceed 3¢/kWh (average annual marginal energy cost during off-peak hours), plus losses and other variable costs that don't vary by time of day. Typically, rates are set to slightly exceed marginal cost because such costs fluctuate over time. If demand-related costs are recovered in the on-peak energy rates to create a larger energy rate differential to better incent shifting, they should emphasis the morning on-peak period in the winter versus the evening hours.

Attachment E

The Companies' Response to the Public Staff's Data Request No. 1-3(f)

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

With respect to the **"DEC-DEP NC - Marginal Cost Study 9.10.21"** spreadsheet that the Companies provided in response to the Public Staff's DR 1:

a. Provide a basis for, and a calculation of the "annual kWh savings" identified on line 5 of the respective rate schedule tabs.

b. Please explain the note on line 5 that says, "kWh comprised by self-service (consumed behind-the-meter) or exported on a monthly basis."

c. Please identify the source[2] of the avoided production, capacity, and T&D values on 6 through 8 of the respective rate schedule tabs.

d. Please explain the note on line 7 that says, "New Plant." What plant is included in the term?

e. Please explain the note on line 8 that says, "New Transmission and Distribution." What plant items are included in the term?

f. Please provide the calculation for the "revenue reductions" on line 14 of the respective rate schedule tabs.

Response:

a. The annual kWh savings on row 5 represents average annual kWh solar generation per-customer, based on 2019 hourly solar generation load profiles. The following Excel file contains the solar generation profiles and shows the kWh calculations ("PSDR 1-3a - DEC-DEP Solar Generation Load Profiles.xlsx").

PSDR%201-3a%20-
%20DEC-DEP%20Sol

[2] PURPA (Public Utilities Regulatory Policy Act 1978) avoided cost, integrated resource planning, DSM/EE rider, or other proceeding should include the specific docket number of the proceeding and exhibit.

b. As noted in response to question 3.a. the data on line 5 represents average annual kWh solar generation per-customer. The note expresses that the solar generation kWh is comprised of the following two components:

- solar kWh used to serve the customer's load (i.e., self-service),
- solar kWh in excess of the customer's load (i.e., export capability).

c. Avoided electric capacity costs were based on the same unit capacity cost, nominal MW rating, escalation rate and seasonal allocations used in Docket No. E-100, Sub 158.

Avoided electric production costs were derived using the same underlying resource plan, production cost model, and cost inputs reflected in Docket No. E-100, Sub 158, with the exception that a 100 MW purchase in all hours was used to model the avoided energy in Docket E-100, Sub 158, while the hourly savings shape of DEC (or DEP) projected EE portfolio was used to model the avoided energy for this solar analysis.

Avoided electric T&D costs were based on the results of the DEC and DEP 2017 T&D studies and escalated by the Handy Whitman Index.

The avoided production, avoided capacity cost and avoided T&D rates used in the solar analysis are also the same as those used for vintage year 2022 EE programs in the 2021 DEC and DEP DSM/EE Rider Filings (Docket Nos. E-7, Sub 1249 and E-2, Sub 1273, respectively).

d. The note on the "avoided electric capacity" line item simply describes the new CT identified in Docket No. E-100, Sub 158.

e. The note on the "avoided electric T&D" line item was intended to describe that solar generation reduces the need for new T&D expenditures.

f. Please see the attached spreadsheets which come from a SAS model of customers with rooftop solar and second meters.

DECNC_2019_v10_Rev0_12Oct2021.xlsx

DEPNC_2019_v10_Rev0_12Oct2021.xlsx

Attachment F

The Companies' Response to NC WARN's Data Request No. 2-1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

The following table from the 2020 EIA "North Carolina Electricity Profile"[1] provides a breakdown of the retail consumption of electricity by DEC and DEP residential, commercial, and industrial customers in 2020.

Table 3. Top five retailers of electricity, with end use sectors, 2020						
North Carolina						
Megawatt-hours						
	Entity	**Type of provider**	**All sectors**	**Residential**	**Commercial**	**Industrial**
1	Duke Energy Carolinas, LLC	Investor-owned	55,703,047	21,558,142	22,707,156	11,421,625
2	Duke Energy Progress - (NC)	Investor-owned	36,297,536	15,727,252	12,755,572	7,814,712

[1] https://www.eia.gov/electricity/state/northcarolina/.

Provide: (1) the cost to serve each of these three customer classes by DEC and DEP (separately) in 2020, and (2) the revenue received by DEC and DEP from each of these three customer classes in 2020.

Response:

1. DEP and DEC do not prepare cost of service studies along the three customer classes listed in the data request. Please see the response to NC WARN DR 1-12 and the COS studies provided therein.

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	2,992,717,721	3,051,598,700
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	2,186,033,331	2,372,750,932
5	Large (or Ind.) (See Instr. 4)	1,135,695,981	1,221,199,824
6	(444) Public Street and Highway Lighting	44,518,362	43,701,721
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	215	79
10	TOTAL Sales to Ultimate Consumers	6,358,965,610	6,689,251,256
11	(447) Sales for Resale	419,463,117	541,810,531
12	TOTAL Sales of Electricity	6,778,428,727	7,231,061,787
13	(Less) (449.1) Provision for Rate Refunds	-13,178,017	25,560,067
14	TOTAL Revenues Net of Prov. for Refunds	6,791,606,744	7,205,501,720
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,364,195	19,713,241
17	(451) Miscellaneous Service Revenues	13,407,012	16,566,062
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	94,854,906	98,444,854
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-7,268,963	-45,896,162
22	(456.1) Revenues from Transmission of Electricity of Others	96,070,541	99,206,132
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	202,427,691	188,034,127
27	TOTAL Electric Operating Revenues	6,994,034,435	7,393,535,847

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.
				1
28,162,388	28,724,810	2,306,162	2,260,939	2
				3
27,628,755	29,576,666	366,952	362,174	4
19,612,942	21,271,896	6,099	6,123	5
312,800	320,907	22,939	21,581	6
				7
				8
				9
75,716,885	79,894,279	2,702,152	2,650,817	10
8,857,220	10,026,499	21	20	11
84,574,105	89,920,778	2,702,173	2,650,837	12
				13
84,574,105	89,920,778	2,702,173	2,650,837	14

Line 12, column (b) includes $ 25,683,035 of unbilled revenues.

Line 12, column (d) includes 210,485 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) ☐ An Original (2) ☒ A Resubmission	04/29/2021	End of 2020/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	2,056,765,413	2,169,136,266
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,207,316,671	1,340,418,584
5	Large (or Ind.) (See Instr. 4)	647,180,713	681,887,498
6	(444) Public Street and Highway Lighting	21,015,304	21,064,526
7	(445) Other Sales to Public Authorities	82,671,631	88,000,375
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,014,949,732	4,300,507,249
11	(447) Sales for Resale	1,148,287,909	1,468,268,974
12	TOTAL Sales of Electricity	5,163,237,641	5,768,776,223
13	(Less) (449.1) Provision for Rate Refunds	-4,832,879	-1,974,555
14	TOTAL Revenues Net of Prov. for Refunds	5,168,070,520	5,770,750,778
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,587,532	10,652,500
17	(451) Miscellaneous Service Revenues	5,761,208	6,951,940
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	37,275,461	36,092,395
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	14,645,726	2,580,276
22	(456.1) Revenues from Transmission of Electricity of Others	75,742,594	84,191,351
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	136,012,521	140,468,462
27	TOTAL Electric Operating Revenues	5,304,083,041	5,911,219,240

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [ ] An Original (2) [X] A Resubmission	04/29/2021	End of 2020/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
17,744,951	18,242,806	1,375,190	1,348,978	2
				3
12,893,934	13,945,036	239,094	236,544	4
10,119,358	10,473,676	4,000	4,026	5
77,152	76,758	1,415	1,416	6
1,418,489	1,452,708	5	5	7
				8
				9
42,253,884	44,190,984	1,619,704	1,590,969	10
22,986,260	24,165,841	9	9	11
65,240,144	68,356,825	1,619,713	1,590,978	12
				13
65,240,144	68,356,825	1,619,713	1,590,978	14

Line 12, column (b) includes $ 13,491,182 of unbilled revenues.
Line 12, column (d) includes 155,136 MWH relating to unbilled revenues

Attachment G

The Companies' Response to the Public Staff's Data Request No. 1-1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Please provide a spreadsheet, with formulas intact that can be used to estimate a customer's monthly bill under proposed Rider RSC and the appropriate TOU-CPP rate schedules for DEC and DEP (collectively referred to as "Companies"). This spreadsheet should enable the Public Staff to calculate the total monthly bill with net exports/imports during each pricing period and system capacity as inputs. The purpose of this request is to better understand how the non-by-passable charges, grid access fee (GAF), and monthly minimum bill (MMB) interact.

Response:

The attached Excel file "PSDR1-1 NC RSC.xlsx" includes formulas to estimate a customer's monthly bill under proposed Rider RSC.

PSDR1-1%20NC%20
RSC.xlsx

Attachment H

The Companies' Response to NC WARN's Data Request No. 1-11

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Provide all net energy metering solar full cost of service studies conducted by the Companies to support the proposed net energy metering solar tariffs.

Response:

Please see attached.

NC%20WARN%20DR1-11_DEC-DEP%20N

NC%20WARN%20DR1-11_NC%20NEM%

Attachment I

The Companies' Response to NC WARN's Data Request No. 5-1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

In the spreadsheet that the Companies provided in response to Public Staff Data Request No. 1, the Companies demonstrate which bill charges count toward the Monthly Minimum Bill ("MMB"). In the DEC example, the customer accrues $58.82 in volumetric energy charges (lines 19-22), but only $9.92 of those volumetric energy charges are counted toward the MMB (lines 42-44). The $9.92 is the wholesale energy component of the volumetric energy charges.

On the other hand, the Companies' Joint Petition in the above-referenced docket indicates that the non-wholesale energy component of the volumetric energy charge will be credited to the MMB: "The MMB can be satisfied by . . . the portion of the monthly volumetric energy charges specific to customer and distribution costs." *See* page 14.

In response to the present Data Request No. 5-1, clarify whether (1) the entire monthly volumetric energy charge is credited to the MMB, (2) only the non-wholesale

Response:

The $9.92 referenced is not a wholesale value, but rather the portion of volumetric rates that recover customer and distribution costs. As page 14 of the Joint Application notes, "The MMB can be satisfied by (i) the basic customer charge or basic facilities charge in the applicable TOU-CPP Tariff, as defined below (each a "Basic Charge"), and (ii) the portion of the monthly volumetric energy charges specific to customer and distribution costs, and riders." This is shown in the Minimum Bill Charge Calculation in the spreadsheet provided in response to Public Staff Data Request 1-1 in rows 38-50.

Attachment J

The Companies' Response to NC WARN's Data Request No. 4-4

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Provide the detailed supporting calculations/workpapers, etc., for the following values provided in the Companies' response to NC WARN's DR 1-11 (1st xls spreadsheet response):

- 2022 DEC-NC RE System Benefits – Avoided Electric T&D = $247
- 2022 DEC-NC RE System Revenue Reduction - Current = $1,025
- 2022 DEC-NC RE System Revenue Reduction - Proposal = $708
- 2022 DEC-NC RS System Benefits – Avoided Electric T&D = $196
- 2022 DEC-NC RS System Revenue Reduction - Current = $909
- 2022 DEC-NC RS System Revenue Reduction - Proposal = $643
- 2022 DEP-NC RE-RS Wtd Avg System Benefits – Avoided Electric T&D = $127
- 2022 DEP-NC RE-RS Wtd Avg System Revenue Reduction - Current = $1,171
- 2022 DEP-NC RE-RS Wtd Avg System Revenue Reduction - Proposal = $821

Response:

Work in progress

Attachment K

The Companies' Response to NC WARN's Data Request Nos. 1-5 & 1-10

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Identify the modeled increase in utility-scale solar between 2021 and 2026 in DEC service territory, if not explicitly identified in Data Request No. 1-3.

Response:

Please see the attached file NC_WARN_DR1-4_1-5_1-9_1-10.xlsx.

NC_WARN_DR1-4_1-5_1-9_1-10.xlsx

NC WARN DR1-4	2021	2026	Change
DEC NEM Solar Capacity (MWs)	256	529	274

Notes:
Data represents cumulative nameplate capacity on a year end basis
Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-5	2021	2026	Change
DEC Utility Scale Solar Capacity (MWs)	1,465	2,896	1,431

Notes:
Data represents cumulative nameplate capacity on a year end basis
Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-9	2021	2026	Change
DEP NEM Solar Capacity (MWs)	120	254	134

Notes:
Data represents cumulative nameplate capacity on a year end basis
Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-10	2021	2026	Change
DEP Utility Scale Solar Capacity (MWs)	3,215	4,435	1,221

Notes:
Data represents cumulative nameplate capacity on a year end basis
Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

% Growth '21-'26	% Utility Scale '21	% Utility Scale '26
60%	93%	90%

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Identify the modeled increase in utility-scale solar between 2021 and 2026 in DEP service territory, if not explicitly identified in Data Request No. 1-8.

Response:

Please see the attached file NC_WARN_DR1-4_1-5_1-9_1-10.xlsx.

NC_WARN_DR1-4_1-5_1-9_1-10.xlsx

NC WARN DR1-4	2021	2026	Change
DEC NEM Solar Capacity (MWs)	256	529	274

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-5	2021	2026	Change
DEC Utility Scale Solar Capacity (MWs)	1,465	2,896	1,431

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-9	2021	2026	Change
DEP NEM Solar Capacity (MWs)	120	254	134

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-10	2021	2026	Change
DEP Utility Scale Solar Capacity (MWs)	3,215	4,435	1,221

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

% Growth '21-'26	% Utility Scale '21	% Utility Scale '26
60%	93%	90%

Attachment L

The Companies' Response to NC WARN's Data Request Nos. 1-4 & 1-9

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Identify the modeled increase in NEM solar between 2021 and 2026 in DEC service territory, if not explicitly identified in Data Request No. 1-3.

Response:

Please see the attached file NC_WARN_DR1-4_1-5_1-9_1-10.xlsx.

NC_WARN_DR1-4_1-5_1-9_1-10.xlsx

NC WARN DR1-4	2021	2026	Change
DEC NEM Solar Capacity (MWs)	256	529	274

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-5	2021	2026	Change
DEC Utility Scale Solar Capacity (MWs)	1,465	2,896	1,431

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-9	2021	2026	Change
DEP NEM Solar Capacity (MWs)	120	254	134

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-10	2021	2026	Change
DEP Utility Scale Solar Capacity (MWs)	3,215	4,435	1,221

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

% Growth '21-'26	% Utility Scale '21	% Utility Scale '26
60%	93%	90%

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Identify the modeled increase in NEM solar between 2021 and 2026 in DEP service territory, if not explicitly identified in Data Request No. 1-8.

Response:

Please see the attached file NC_WARN_DR1-4_1-5_1-9_1-10.xlsx.

NC_WARN_DR1-4_1-5_1-9_1-10.xlsx

NC WARN DR1-4	2021	2026	Change
DEC NEM Solar Capacity (MWs)	256	529	274

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-5	2021	2026	Change
DEC Utility Scale Solar Capacity (MWs)	1,465	2,896	1,431

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-9	2021	2026	Change
DEP NEM Solar Capacity (MWs)	120	254	134

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

NC WARN DR1-10	2021	2026	Change
DEP Utility Scale Solar Capacity (MWs)	3,215	4,435	1,221

Notes:

Data represents cumulative nameplate capacity on a year end basis

Data does not represent any additions in utility-scale solar as a part of the carbon plan from H.B. 951

% Growth '21-'26	% Utility Scale '21	% Utility Scale '26
60%	93%	90%

Attachment M

The Companies' Response to NC WARN's Data Request Nos. 4-1 & 4-2

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

To the extent that DEC is predicting that the summer month peak will shift substantially into the evening between 2021 and 2026, as reflected in the Companies' July 22, 2021 PowerPoint *Carolinas Refreshed TOU Periods* (pp. 7-14) in the Rate Design Study stakeholder process, please provide (a) all data supporting this modeled shift, and (b) the model used to predict the shift, and (c) all modeling input parameters, and (d) the basis for any assumptions used in defining the numeric value of the parameters.

Response:

As answered in NC WARN DR 1-3 and 1-8, the Companies are not proposing new time-of-use windows in this docket.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

To the extent that DEP is predicting that the summer month peak will shift substantially into the evening between 2021 and 2026, as reflected in the Companies' July 22, 2021 PowerPoint *Carolinas Refreshed TOU Periods* (pp. 7-14) in the Rate Design Study stakeholder process, please provide (a) all data supporting this modeled shift, and (b) the model used to predict the shift, and (c) all modeling input parameters, and (d) the basis for any assumptions used in defining the numeric value of the parameters.

Response:

DEP's analysis regarding high-cost time periods during the summer months between 2021 and 2026 was presented in the Comprehensive Rate Design Study stakeholder process and was used to develop the TOU periods approved in Docket No. E-2, Sub 1280. The Companies are not reviewing this analysis or predicting any revised shifts for the periods between 2021 and 2026 in this docket. Finally, as answered in response to NC WARN DR 1-3 and 1-8, the Companies are not proposing new time-of-use windows in this docket.

Attachment N

The Companies' Response to the Public Staff's Data Request No. 1-2

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

With respect to the statement on page 7 of the Joint Application regarding the efforts to ensure that NEM customers "pay their full fixed cost of service," please identify the "full fixed cost of service" for NEM and non-NEM customers (both residential and non-residential[1]) in terms of total cost to serve, costs per kWh, or other appropriate metric. The response should include the calculation of the full fixed cost, the constituent inputs to the algorithm and source of those inputs including any reference to the cost frameworks or the cost of service studies (COSS) that are the basis for this filing.

Embedded Cost NEM Analysis.xlsx

DEC-DEP NC - Marginal Cost Study

Response:

Attached, please see the final versions of the embedded and marginal cost studies and supporting modeling, which are updated and vary slightly from those cost studies shared previously in an informal data request.

PSDR1-2 Attachments.zip

Fixed cost of service includes all costs that the utility needs to invest to have a system ready to provide safe, reliable electricity. In other words, it would be the costs incurred if the utility planned and built a system to provide electricity and then customers decided to not actually use any kWhs. In technical terms, fixed costs include all costs that are not classified as energy costs including production capacity, transmission capacity, distribution capacity and customer costs.

The requirement for NEM customers to "pay their full fixed cost of service" means that paying for the full fixed cost to serve is a base level. However, this does not necessarily exclude the consideration of reductions in energy costs – so long as the full fixed costs are still recovered.

[1] The Public Staff is including non-residential customers in this data request because those customers will continue to be eligible for the current NEM schedules (Riders NM for both Companies).

Through comparing the embedded reduction in cost to serve with revenue reduction (i.e., the embedded cross-subsidy study), the Companies conclude that, under the proposal, NEM customers would be contributing their fair share towards recovery of embedded costs – including all categories of fixed costs. In other words, if all costs are appropriately recovered then this would include the fixed cost to serve.

It should be noted that some parties may draw distinctions between costs that are fixed in the short term but can be changed over the long term. This nuance is relevant in the context of marginal costs, but since embedded costs (or the costs that feed into the revenue requirement) have already been incurred, the distinction between short/long-term fixed costs is not relevant for embedded costs.

Attachment O

The Companies' Response to NC WARN's Data Request No. 1-16

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Provide any value-of-solar studies completed by the Companies in the last ten years for distributed (rooftop) solar.

Response:

The Company has calculated value of solar through both embedded and marginal lenses. These studies are provided through question 2 in the Public Staff's Data Request sent December 22, 2021.

Attachment P

The Companies' Response to the Public Staff's Data Request No. 1-28

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Please explain why the Companies declined to perform a Value of Solar Study to assist in developing the proposed Rider RSC.

Response:

While the Companies did not retain a third party to perform a Value of Solar Study (VOSS), as part of the Comprehensive Rate Review stakeholder process, the Companies did perform a VOSS, which was shared with stakeholders. Duke Energy provided embedded and marginal cost analyses, which used North Carolina Utility Commission (NCUC)-approved methodologies for rate design and evaluation of Demand-Side Management and Energy Efficiency (DSM/EE) programs. The Companies believe this is the appropriate way to value rooftop solar assets because these are the same methods utilized to allocate embedded costs or evaluate any DSM/EE program. Duke's modeling of rooftop solar also used the same valuation of avoided cost.

Through numerous regulatory proceedings, the Public Staff and NCUC have provided the appropriate level of independent review that has resulted in finding the methodologies the Companies used to perform its internal VOSS to be appropriate, prudent and in the public interest.

Attachment Q

The Companies' Response to NC WARN's Data Request No. 2-4

NC WARN
Docket No. E-100, Sub 180
Net Metering
NC WARN Data Request No. 2
Item No. 2-4

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Page 11 of the Companies' Application in the above-captioned docket states: "In fact, the Companies surveyed several organizations participating in these workshops, and that survey revealed that 80% of those organizations were either "supportive" or "very supportive" of the overall NEM proposal offered by the Companies." Provide all survey responses conducted by the Companies as referenced in theforgoing statement.

Response:

Please refer to attached spreadsheet summarizing the survey conducted as part of the Comprehensive Rate Design Study.

NC%20WARN%20DR2-4_NEM%20and%2

Stakeholder (individual names deleted)	Organization	Based on what you know today, how supportive are you of the proposed NEM solution as a starting point for potential NC NEM reform? Text	Ranking (1 - least supportive, 5 - most supportive)	Do you support the general framework of the recently approved DEC TOU-CPP rates for expansion and filing in DEP? Text	Ranking (1 - least supportive, 5 - most supportive)	Do you have any specific concerns, suggestions, or questions for TOU-CPP rates or net metering reform?
	Appalachian Voices	(1) Not supportive at all of current proposal	1	(1) Not supportive at all of DEC TOU-CPP framework	1	The TOU-CPP framework is making far too significant of changes based on far too uncertain of projections 10 years out. For instance, moving the summer TOU-CPP period to the 6-9pm timeframe moves it completely outside of the highest current load periods, which are in the 3:00-6:00 pm hours.
	SACE	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	
	Coastal Conservation League	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	Going forward, it will be interesting to understand the cost-benefit of all-electric vs. dual-fuel solar customers under TOU rates.
	Appalachian Voices	(1) Not supportive at all of current proposal	1	(1) Not supportive at all of DEC TOU-CPP framework	1	1. Don't discriminate against customer-owned, net metered distributed generation. If a customer chooses to make their own personal investment in an on-site solar system, the utility should treat generation from that resource the same as if the customer had invested in a new energy efficient HVAC system or other EE improvement. At least up to the point where the customer has zeroed out their monthly energy imports, the value of customer-owned DG (solar, etc) should be the retail rate. Excess generation/exports may be treated differently. The TOU proposal discriminates against NEM customers, treating them differently for no real reason. 2. TOU periods should begin at current load levels and be adjusted as necessary moving forward. 3. Duke should provide actual hourly load data for Jan through Aug of 2021 so we can assess the variance b/w projected and actual load to better understand what variance/errors may exist in future load projections. 4. very few low-income, or even moderate-income customers will be able to take advantage of the TOU structure, load shifting, EV's, etc in a manner that maximizes the value of those pieces. So what this proposal does is place equity and low-income access on the backburner, yet again, and says "we'll deal with that later, let's get this less accessible, less equitable replacement for net metering in place first." That just continues the historical trend of deprioritizing equity instead of leading with it. 5. I'm concerned about how rushed this is given the obvious problems with the current TOU proposal. We still have plenty of time to come up with something better and more accessible for more customers. It may be something that looks like Duke's proposal, but without the high minimum bill and with what we believe to be more appropriate TOU periods.
	Southern Environmental Law Center	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	Part of what made the Duke Energy Solar Choice NEM tariffs work from our perspective in South Carolina was the inclusion of the proposed Solar Saver EE incentive (pending approval before the SC PSC) - we did not discuss that incentive very much in the context of the rate design study, but I think it is important to note that the existence of the proposed incentive informs SELC's support for the NEM TOU-CPP rate structure, as is the commitment to continue working on a low-income solar NEM program with Duke. But we also see real value in the TOU-CPP rate design for integrating a broader array of DERs (form smart thermostats, EVs, to battery storage).
	NC Sustainable Energy Association	(5) Very supportive of current proposal	5	(4) Supportive of DEC TOU-CPP framework with minor changes	4	We would like the final report/filing to specify a process for and what triggers might result in future changes to the TOU periods. We would also like to make sure the net metering final report/filing makes a clear connection to the Solar EE/DSM incentive that was a part of the SC NEM settlement.
	Vote Solar	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	
	Sunrun	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	
	Utility Management Services Inc.	(N/A) Still assessing/undecided	-	(3) Somewhat supportive of DEC TOU-CPP framework with moderate cha	3	The TOU - CPP rates need to be modified so that they no longer cut off at 75 KW. They should go to at least 5,000 KW. The OPT rates in the DEC area should be modified so that they don't only work for customers with load factors of more than 50%. Most customers have a much lower load factor than that. Alternatively, an energy only TOU rate could be used to provide an option for lower load factor customers.
	CIGFUR	(3) Somewhat supportive with moderate changes to current prop	3	(N/A) Still assessing/undecided	-	My suggestions pertain only to non-resi NEM. As discussed in the non-resi NEM subgroup this morning, we'd like to see either virtual NEM or expanded GSA program capacity; increased or eliminated system size cap on NEM participation for large C&I customers; and incorporation of stand-some storage and solar + storage into NEM conversation.
	Synapse Energy Economics	(4) Supportive with minor changes to current proposal	4	(4) Supportive of DEC TOU-CPP framework with minor changes	4	Duke's methodology for developing TOU time periods and costs appears generally reasonable, and the overarching TOU-CPP framework is sound. From a review of the available data, inclusion of the 5 pm hour in the on-peak period warrants consideration, but of course this must be balanced with other considerations (e.g., the duration of the on-peak window). In the future, it would be good to have more granular data and workpapers available to stakeholders at the outset.
		(3) Somewhat supportive with moderate changes to current prop	3	(4) Supportive of DEC TOU-CPP framework with minor changes	4	
	The Lion Electric	(N/A) Still assessing/undecided	-	(N/A) Still assessing/undecided	-	My concerns center around the impacts to Total Cost of Ownership for fleets of medium and heavy duty electric vehicles. The large-scale changes to electrification require that utilites offer viable solution regarding the cost to charge. The market needs clear and practical price signals on appropriate, grid-friendly times to charge, incentivized by reasonable demand charges and favorable Discount TOU periods. Customers also need robust incentives to help with first-costs of upgrading infrastructure, and technical assistance in understanding and solving the challenges of infrastructure upgrades.
	on behalf of NC WARN	(1) Not supportive at all of current proposal	1	(N/A) Still assessing/undecided	-	NC WARN has several concerns, which we have tried to raise during the course of the stakeholder proceeding. Procedurally, we are concerned that net metering was not appropriate for the "fast track" process, that insufficient information was shared concerning issues crucial to net metering, that insufficient opportunity was provided to evaluate what little information was shared, and that the MOU in SC should not have been proposed as the baseline for discussion. Substantively, we are concerned that the minimum monthly bill and TOU proposals are extremely disadvantageous to solar and have not been meaningfully vetted during the stakeholder process. We have other concerns, which were previously raised during the stakeholder event.
	on behalf of NC WARN	(1) Not supportive at all of current proposal	1	(1) Not supportive at all of DEC TOU-CPP framework	1	
	Alliance for Transportation Electrification	(5) Very supportive of current proposal	5	(5) Very supportive of DEC TOU-CPP framework	5	

Attachment R

The Companies' Response to NC WARN's Data Request Nos. 1-3 & 1-8

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

To the extent that DEC is proposing time of use windows based upon its prediction that peak will shift substantially by 2026, please provide (a) all data supporting this modeled shift, and (b) the model used to predict the shift, and (c) all modeling input parameters, and (d) the basis for any assumptions used in defining the numeric value of the parameters.

Response:

DEC is not proposing new time-of-use (TOU) windows in this docket. The filing in this docket only requires NEM customers to be served under Schedule RS-TC and RE-TC, but it does not establish new TOU windows.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

To the extent that DEP is proposing time of use windows based upon its prediction that peak will shift substantially by 2026, please provide (a) all data supporting this modeled shift, and (b) the model used to predict the shift, and (c) all modeling parameters, and (d) the basis for any assumptions used in defining the numeric value of the parameters.

Response:

DEP is not proposing new time-of-use windows in this docket. The filing in this docket only requires NEM customers to be served under Schedule R-TOU-CPP, but it does not establish new TOU windows.