STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1276

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation	)))))	**DIRECT TESTIMONY OF WILLIAM E. POWERS AND RAO KONIDENA FOR NC WARN**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Mr. Powers: My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

Mr. Konidena: My name is Rao Konidena. My business address is Rakon Energy LLC, 2309 Auerbach St, Roseville, MN 55113.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. Mr. Powers: My employer is Powers Engineering. I am the founder and principal of the company.

Mr. Konidena: My employer is Rakon Energy LLC where I am the president.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. Mr. Powers: I am a consulting and environmental engineer with 40 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness in high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. Furthermore, I have offered reports or testimony in numerous utility resource planning proceedings throughout the country, including in the State of North Carolina.

I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego" (2020), "(San Francisco) Bay Area Smart Energy 2020" (2012), and "North Carolina Clean Path 2025" (2017), and I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources.

I have a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from UNC – Chapel Hill, and I am a registered professional engineer in California and Missouri.

Mr. Konidena: I have been an independent energy consultant for five years, primarily focusing on Regional Transmission Organization practices and policy. I worked in Transmission Asset Management at Midcontinent Independent System Operator ("MISO"), similar to PJM, from September 2003 to May 2018. I started as an Applications Engineer for Planning, where I ran Loss of Load Expectation ("LOLE") studies, Capacity Benefit Margin ("CBM") calculations, and Load Deliverability analysis for the MISO Transmission Expansion Plan ("MTEP"). MISO's MTEP is similar to PJM's Regional Transmission Expansion Plan ("RTEP").

I was later promoted to Lead, Resource Forecasting in 2006, responsible for a team of engineers running the capacity forecasting software EPRI EGEAS. That forecasting work is incorporated in the MTEP non-transmission alternatives section. After a promotion to Manager of Resource Forecasting in 2009, I led Demand Response and Energy Efficiency forecasting for MTEP, including interfacing with consultants at Applied Energy Group and NG Planning.

I worked in compliance, process, and project management for the Transmission Asset Management ("TAM") division as Senior Manager of TAM Operations from 2013 to 2015. In this role, my team and I were responsible for division-wide financial and strategic planning, supporting corporate planning and compliance efforts. I came back to the Policy Studies department in the Principal Policy Advisor role for MISO in 2015, leading the long-term load forecasting project with Purdue University's State Utility Forecasting Group and Applied Energy Group demand response ("DR"), energy efficiency ("EE") and distributed generation ("DG") potential study at MISO.

Before leaving MISO in 2018, I led policy efforts on energy storage and distributed energy resources within economic transmission planning. I presented to MISO state commissions, including the Iowa Utilities Board, the South Dakota State Public Utilities Commission, and the Organization of MISO States.

I received a Bachelor of Engineering in Electrical & Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. Mr. Powers: Yes. I testified on behalf of NC WARN in Docket No. E-7, SUB 1214, Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina, as well as Docket No. E-2, SUB 1219, Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina. Further, I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in numerous prior dockets, such as Docket No. E-2, SUB 1089 and Docket No. E-100, SUB 180. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

Mr. Konidena: I have not testified before N.C. Utilities Commission. As an independent consultant, I have submitted direct testimonies on behalf

of my clients at the Public Service Commission of Wisconsin (Transmission Line Certificate of Public Convenience & Need docket), Minnesota Public Utilities Commission (Aggregator of Retail Customer docket), Kansas Corporation Commission (Demand Response Aggregator docket), and California Public Utilities Commission (Diablo Canyon Power Plant extension docket). Additionally, I have provided comments representing myself at Minnesota Public Utilities Commission and Colorado Public Utilities Commission on Integrated Distribution Planning. Finally, I have submitted comments representing myself at the Texas Public Utilities Commission on Reliability Metrics and Aggregation of the DERs Pilot Program.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of this testimony is to examine the: 1) cost and purpose of the proposed Duke Energy Carolinas, LLC ("DEC") upgrades to the Clinton 100 kV transmission line and to the Lee 100 kV and the Piedmont 100 kV transmission lines, 2) viability of distributed solar as an alternative to industrial-scale solar projects interconnecting to these two 100 kV transmission lines that should have been evaluated as an alternative by DEC, and 3) lack of factual evidence to support a modification to the DEC non-residential net-energy metering (NEM) tariff. The proposed non-residential NEM tariff should be subject to a separate application.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. This testimony is organized as follows:

I. Executive Summary

II. Cost and Purpose of the Proposed 100 kV Projects

III. The Distributed Solar Alternatives to the Proposed 100 kV Upgrades are Cost-Effective

IV. The Distributed Solar Alternative to the 100 kV Transmission Line Upgrades should have been Evaluated by DEC

V. The Non-Residential NEM Solar Tariff should be Subject to a Separate Application

I. EXECUTIVE SUMMARY

This testimony examines the high cost of the proposed DEC transmission upgrades to three 100 kV transmission lines, Clinton, Lee, and Piedmont, relative to the specific solar projects under study by DEC that would interconnect to these lines. The effect of this "transmission cost adder" on utility-scale solar project cost is compared to distributed solar, both net-energy metered (NEM) rooftop solar and wholesale commercial rooftop and parking lot solar, to demonstrate that, in 2027 when these 100 kV lines are projected to come online, distributed solar will be the lower-cost solar alternative. Finally, this testimony advocates for a separate application process for DEC's proposed non-residential NEM tariff revisions.

II. COST AND PURPOSE OF THE PROPOSED 100 kV PROJECTS

Q. PLEASE DESCRIBE THE SCOPE AND COST OF THE PROPOSED 100 kV PROJECTS NC WARN IS CONCERNED ABOUT.

A. Appendix P of Duke Energy Carolinas and Duke Energy Progress's (collectively called "the Companies") proposed Carbon Plan, discusses "Transmission System Planning and Grid Transformation."[1] NC WARN is specifically concerned with the high apparent cost of the proposed upgrades to the Lee 100 kV (Lee-Shady Grove), Piedmont 100 kV (Lee-Shady Grove), and the Clinton 100 kV (Bush River-Laurens) transmission lines listed in Table P-3 of Appendix P to the Carbon Plan.[2] The Lee and Piedmont 100 kV lines start and end at the same points and are treated as one project by DEC for budgetary purposes. NC WARN follows the same convention in this testimony, addressing the Lee and Piedmont 100 kV upgrade as one upgrade project.

Q. WHAT DOES DEC IDENTIFY AS THE COST OF THE CLINTON 100 kV AND LEE AND PIEDMONT 100 kV UPGRADES?

A. The costs of the 1) Clinton 100 kV and 2) the Lee and Piedmont 100 kV upgrades are $90,248,797 and $80,909,775 respectively.[3]

Q. WHAT IS THE IN-SERVICE DATE FOR THE LEE AND PIEDMONT 100 kV LINES?

A. DEC Exhibit TC-7, "*MYRP Transmission Project Details,*" lists December 2026 as the in-service date for both Clinton 100 kV and Lee and Piedmont

[1] The Companies' Carbon Plan, Appendix P, Table P-3, p. 14.
[2] Ibid.
[3] DEC Exhibit TC-7: MYRP Transmission Project Details

100 kV lines. This is a 42-month project timeline starting from July 2023.[4] In contrast, the subsequent (December 2022) NCUC Carbon Plan Order identified a 48-month development timeline for these projects.[5] DEC provides no information in its GRC testimony for the difference in project timelines.

Q. WERE ANY SOLAR, OR SOLAR AND STORAGE, PROJECTS INCLUDED IN THE PHASE 1 OR PHASE 2 CLUSTER STUDIES THAT WOULD INTERCONNECT WITH THE LEE AND PIEDMONT 100 kV TRANSMISSION LINE(S)?

A. No. No solar projects interconnecting to the Lee and Piedmont 100 kV transmission lines were identified in either the Phase 1 or Phase 2 Cluster Studies. In contrast, DEC identified three solar projects that would interconnect to the Clinton 100 kV line in the Phase 1 Cluster Study and one more in the Phase 2 Cluster Study. Therefore, the Clinton 100 kV upgrade will serve as the representative case in this testimony for the cost reasonableness of both 100 kV upgrade projects for the purpose of facilitating solar development in what Duke Energy has identified as the "red zone."

Q. WHAT REASON DID DEC GIVE FOR CLINTON 100 kV UPGRADE?

[4] Ibid.
[5] NCUC, Carbon Plan Order, December 30, 2022, p. 115.

A. In the Carbon Plan, Duke testified that DEC Project #4 (Clinton 100 kV line) will be needed to interconnect hundreds of MWs of renewable generation in the red zone, and that it would take 48 months to build the Clinton 100 kV line.[6]

Q. WHAT IS THE REASONING THAT DUKE ENERGY GIVES FOR PRIORITIZING PROJECTS LIKE THE CLINTON 100 kV IN THE RED ZONE?

A. The reasoning is circular. Duke Energy stated in its Carbon Plan testimony that it discourages solar developers from proposing projects in the red zone, but the developers do it anyway:[7]

> The history of solar generator interconnection requests in DEC and DEP shows that solar facilities continue to request interconnection in these red zones, despite published guidance from DEC and DEP that locating solar in the red zones will require significant network upgrades.

Duke Energy goes on to state that it received about 1,500 MW of solar bids in its 2022 Solar Procurement that are located in non-congested areas that would not require transmission upgrades to be deliverable.[8] Yet solar developer preference for cheap land in the red zone is then presented as the justification for Duke Energy to propose a major transmission buildout

[6] Carbon Plan, p. 115: "However, Duke testified that that prior generator interconnection studies and the supplemental studies demonstrate that DEC Project #4 (Clinton 100 kV line) and DEP Project #7 (Erwin – Fayetteville 115 kV line) will be necessary to integrate hundreds of MW of generation in the Red Zone area. Tr. vol. 28, 130-32. Furthermore, Duke estimated that DEC Project #4 will take 48 months to build."

[7] Docket No. E-100, Sub 179, 2022 Biennial Integrated Resource Plan and Carbon Plan, Direct Testimony of Roberts and Farver, August 19, 2022, p. 21.

[8] Ibid, p. 36. "Of the more than 5,000 MW of proposals received, over 70% of the MW are located in known red-zone areas."

there.[9] However, Duke Energy presents no evidence in its testimony that it has ever done a rigorous comparative cost evaluation of preferentially selecting solar projects in non-congested areas, even if incrementally higher cost to projects located in the red zone, to avoid the high cost of transmission upgrades in the red zone.

Q. HAS DEC IDENTIFIED THE TRANSMISSION UPGRADE COSTS FOR THE SPECIFIC SOLAR PROJECTS THAT WOULD INTERCONNECT TO THE CLINTON 100 kV LINE?

A. Yes. These are nearer-term projects to be procured under the Competitive Procurement of Renewable Energy process.[10, 11] As noted, DEC identified three solar projects in the Phase 1 Cluster Study that will interconnect to Clinton 100 kV transmission circuits.

Q. WHAT ARE THE TRANSMISSION COST ADDERS FOR THE THREE SPECIFIC SOLAR PROJECTS IDENTIFIED BY DEC IN THE PHASE 1 CLUSTER STUDY THAT WOULD INTERCONNECT TO THE CLINTON 100 kV LINE?

[9] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 & Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 7: "Stakeholders from the solar industry have emphasized the need to site solar capacity in DEP's southeastern service territory due to available land and lower land costs to solar developers."

[10] Ibid., p. 2: "On March 14, 2022, the Companies filed their Petition proposing a system-wide solar procurement request for proposal (RFP), which would seek to competitively procure a minimum of 700 megawatts (MW) of utility-owned and third-party solar capacity, after preliminary analysis in advance of the Companies' 2022 Carbon Plan (2022 Solar RFP)."

[11] Ibid, p. 7, footnote 4: "DEC and DEP's Transition Cluster Study Phase 1 results under Generator Interconnection Information, Generator Study, Transition Cluster folder. DEC: https://www.oasis.oati.com/duk/; DEP: https://www.oasis.oati.com/cpl/."

A. These three solar projects have a combined capacity of 115 MW and a combined transmission upgrade cost of $40.55 million.[12] This is equivalent to an average transmission upgrade cost of $0.39/watt.[13] Two of the three solar projects have transmission upgrade costs of more than $0.50/watt each.[14]

Q. WHAT DOES DEC ESTIMATE THE COST ADDER TO BE FOR THE CLINTON 100 kV LINE UPGRADE?

A. DEC states a cost of $0.20/watt for the Clinton 100 kV upgrade.[15] It does this by projecting a spectacular increase in the upgraded capacity of the double-circuit Clinton 100 kV line and that all of the available capacity is in solar production. According to DEC, the Clinton 100 kV capacity will increase from 116 MVA (~116 MW) to 600 MVA (~600 MW),[16] a five-fold increase in capacity. DEC also assumes that all of this 600 MVA of capacity will be fully utilized by solar power in the short-term. DEC assumes that the average transmission cost adder at full build-out, which

[12] Duke Energy Carolinas, LLC, *Transitional Cluster Study Phase 1 Report*, February 28, 2022, pp. 4-5 and pp. 10-11, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf. Projects are: ID126078 (40 MW), ID164382 (37.5 MW), and ID165980 (37.5 MW). The transmission upgrade costs are $20.14 million, $5.03 million, and $19.38 million, respectively, a total of $44.55 million (p. 11). In addition, these three solar projects may collectively require an Optical Ground Wire (OPGW) upgrade at a cost of $77.498 million (pp. 4-5).

[13] $44,550,000 ÷ 115,000,000 watts = $0.39/W.

[14] ID165980: $19.38 million ÷ 37.5 MW = $0.52/W; ID126078: $20.14 million ÷ 40 MW = $0.50/W.

[15] DEC DR Response 1-5 identified 443.5 MW of solar is contingent upon Clinton 100 kV upgrade. Hence $90,248,797 ÷ 443,500,000 = $0.20/W.

[16] Assumes for the sake of this testimony that MVA equals megawatts (MW).

may be decades away or never occur, is a representative transmission cost adder for any project interconnecting to the upgraded Clinton 100 kV transmission line now.

Q. IS A FIVE-FOLD INCREASE IN THE CAPACITY OF THE CLINTON 100 kV TRANSMISSION LINE, WITH NO INCREASE IN VOLTAGE, CREDIBLE?

A. It is not credible without additional supporting information. A double-circuit 600 MVA capacity for the Clinton 100 kV transmission line would be expected for a double-circuit 230 kV transmission line,[17] not a double-circuit 100 kV line.

Q. HOW MUCH SOLAR CAPACITY IS INTERCONNECTED TO THE CLINTON 100 kV TRANSMISSION LINE NOW?

A. 0 MW.[18]

Q. IF THE EXISTING CLINTON 100 kV LINE(S) HAVE 116 MW OF CAPACITY AVAILABLE FOR SOLAR, AND ONLY 115 MW OF SOLAR PROJECT CONNECTING TO THE CLINTON 100 kV LINE ARE IN THE PHASE 1 QUEUE, IS THERE A NEED FOR THIS PROJECT AT THIS TIME?

A. No.

[17] M. Beaver – Rocky Mountain Power, *Siting Transmission Lines & Substations*, PowerPoint, December 3, 2019, p. 7: https://pscdocs.utah.gov/electric/19docs/1903510/307477CASPRAttachment3Exhibit1.3.14-8-2019.pdf.

[18] DEC Data Request Response NC WARN 1-3.

Q. THE DEC 2022 DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY PHASE 2 REPORT (MAY 2022) INCLUDES AN ADDITIONAL 45 MW SOLAR PROJECT THAT WOULD INTERCONNECT TO THE CLINTON 100 kV TRANSMISSION LINE. DOES THAT CHANGE YOUR OPINION ON THE NEED FOR THE CLINTON 100 kV TRANSMISSION UPGRADE PROJECT?

A. No. One additional 45 MW solar project that would interconnect to the Clinton 100 kV transmission line is included in the DEC DISIS Phase 2 Report.[19] This would increase the total solar capacity that would interconnect to the Clinton 100 kV to: 115 MW + 45 MW = 160 MW. This solar capacity, if it all came online, would require at least a modest upgrade from the current Clinton 100 kV capacity of 116 MW to 160 MW. This is a net increase in capacity of 44 MW.

Q. WHAT IS THE $/WATT TRANSMISSION ADDER COST FOR 44 MW OF INCREMENTAL CLINTON 100 kV CAPACITY?

A. DEC states the cost of the Clinton 100 kV upgrade will be $90,248,797. The transmission capacity cost per watt ($/W) to accommodate all Phase 1 and Phase 2 study-level solar projects that would interconnect to the Clinton 100 kV = $90,248,797 ÷ (44 MW × 10^6 watt/MW) = $2.05/W. This is ten times

[19] Duke Energy Carolinas, *2022 Definitive Interconnection System Impact Study Phase 2 Report*,
May 22, 2022, p. 4 (ID 568308).

higher than the transmission cost adder of $0.20/W stated by DEC in its data response to NC WARN.[20]

Q. WHAT FINAL CONCERNS DO YOU HAVE WITH THE LEE AND PIEDMONT 100 kV UPGRADE?

A. Duke is proposing to reconductor 24 total miles of the Lee 100 kV and Piedmont 100 kV lines between the W. S. Lee combined cycle plant and the Shady Grove tie.[21] The cost of Lee 100 kV and Piedmont 100 kV reconductoring, $80,909,775, equals $3,371,241 per mile. This reconductoring cost, on a per mile basis, is very high compared to available representative pricing. The Midcontinent Independent System Operator (MISO) *Transmission Cost Estimation Guide for the MISO Transmission Expansion Plan (MTEP) 2023* estimates the unit cost of reconductoring a 115 kV line, per circuit, at $0.37 million per mile.[22] The Lee and Piedmont 100 kV lines consist of four circuits total. Therefore, 4 × $0.37 million/mile × 24 miles = $35.5 million. This representative cost is less than one-half the $80,909,775 budget DEC identifies for this reconducting project.

III. THE DISTRIBUTED SOLAR ALTERNATIVES TO THE PROPOSED 100 kV UPGRADES ARE COST EFFECTIVE

[20] DEC DR Response 1-5 identified 443.5 MW of solar is contingent upon Clinton 100 kV upgrade. Hence $90,248,797 ÷ 443,500,000 = $0.20/W

[21] Duke Energy Carolinas, *2022 Definitive Interconnection System Impact Study Phase 2 Report*, May 22, 2022, pp. 58-59.

[22] MISO, *Transmission Cost Estimation Guide For MTEP23*, May 5, 2023, Table 4.1.3, p. 39: https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP23337433.pdf

Q. WOULD DISTRIBUTED SOLAR, NET-METERED OR WHOLESALE, BE MORE COST-EFFECTIVE FOR DEC RATEPAYERS THAN THE THREE SOLAR PROJECTS IDENTIFIED AS INTERCONNECTING TO THE CLINTON 100 kV LINE IN THE PHASE 1 CLUSTER STUDY?

A. Yes. The three utility-scale solar projects, with an average transmission upgrade cost of $0.39/watt, could be substituted with NEM solar in urban and suburban portions of DEC territory. Each 9 kW NEM system would result in a transmission savings of $470 per year, as shown in Table 1 below. This transmission savings is substantially greater than the residential NEM cost-shift between $360 per year and $372 per year that has been asserted by DEC.[23]

Table 1. Calculation of DEC avoided transmission expenditure if NEM solar substituted for three solar projects interconnecting to Clinton 100 kV line

Element	Calculation	Value
Transmission upgrade costs estimated by DEC for 115 MW of utility-scale solar capacity interconnecting to the Clinton 100 kV line	--	$44.55 million
Annualized cost recovery factor for new DEC transmission[24]	--	0.1349

[23] Initial Comments of NC WARN, NCCSC, and Sunrise Durham in the Matter of Investigation of Proposed Net Metering Policy Changes, NCUC Docket No. E-100 Sub 180, March 29, 2022, Attachment A, p. 4, footnote 14.

[24] NCWARN *et al.*'s Initial Comments, Attachment B, *Deployment of NEM Solar Allows Duke Energy to Eliminate New Transmission That Would Otherwise Be Built*, Table 4, p. 5. The annualized transmission cost recovery factor of 0.1349 is calculated from the known annualized cost of $254 million per year for the $1.883 billion San Diego Gas & Electric 500 kV Sunrise Powerlink transmission line ($254 million/yr ÷ $1,833 million = 0.1349/yr).

Annualized transmission upgrade cost	0.1349 x $44.55 million	$6.01 million/yr
Number of 9 kW NEM systems needed to produce 115 MW of solar output	115,000 kW ÷ 9 kW	12,778
Annual value of avoided DEC transmission upgrade cost per 9 kW NEM system	$6.01 million/yr ÷ 12,778 systems	$470/yr/system

Q. IS NEM SOLAR MORE COST BENEFICIAL TO DEC RATEPAYERS THAN THE COST OF THE CLINTON 100 kV UPGRADE NECESSARY TO INTERCONNECT THE THREE SOLAR PROJECTS LISTED IN THE PHASE 1 CLUSTER STUDY?

A. Yes.

Q. IS WHOLESALE COMMERCIAL ROOFTOP AND PARKING LOT SOLAR MORE COST-BENEFICIAL TO DEC RATEPAYERS THAN THE COST OF THE CLINTON 100 kV UPGRADE NECESSARY TO INTERCONNECT THE FOUR SOLAR PROJECTS LISTED IN THE PHASE 1 AND PHASE 2 CLUSTER STUDIES?

A. Yes. This wholesale commercial rooftop and parking lot solar would largely be located in urban and suburban areas of DEC territory.

Q. WHAT IS THE COST OF COMMERCIAL ROOFTOP SOLAR COMPARED TO UTILITY-SCALE SOLAR IN 2023?

A. According to the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), the capital cost of commercial rooftop solar is

$1.40/watt.[25] This compares to a utility-scale solar cost of $1.04/watt. This capital cost difference is decreasing over time. The cost delta between commercial rooftop/par solar and utility-scale solar will be substantially less when the Clinton 100 kV and Lee and Piedmont 100 kV upgrades are operational in 2027.

Q. ARE THE COSTS OF COMMERCIAL ROOFTOP SOLAR AND UTILITY-SCALE SOLAR CONVERGING OVER TIME?

A. Yes. The NREL ATB solar cost data makes clear that commercial rooftop/parking lot solar cost is converging with utility-scale solar cost. The projected cost difference between utility-scale solar and commercial rooftop solar is $16/MWh in 2027, and less than $10/MWh in 2035, as shown in Table 2. This delta could be eliminated for projects using additional Inflation Reduction Act (IRA) incentives for projects < 5 MW. Locating generation and storage near where it is used also avoids the need (and costs) for transmission upgrades and new transmission corridors. Table 2 compares the cost of utility-scale solar and commercial rooftop solar for the years 2023, 2027, 2035, and 2050 using the 2022 NREL ATB and the Class 6 solar insolation category for the Carolinas.[26] Duke Energy assumed the NREL ATB "Advanced" scenario in its proposed Carbon Plan[27]. For that

[25] NREL ATB 2022 spreadsheet, V2 corrected, July 21, 2022: https://data.openei.org/submissions/5716

[26] Ibid; Solar insolation category for Carolinas: https://atb.nrel.gov/electricity/2022/utility-scale_pv . Solar Class 6 capacity factor (in MWac) = 0.258.

[27] Duke Energy proposed Carbon Plan, Appendix E, pp. 99-100.

reason, the solar cost values for the "Advanced" scenarios are used in Table 2.

Table 2. Convergence of utility-scale and commercial rooftop solar cost is occurring over time

Year	Utility-scale solar, Class 6, "Advanced", ($/MWh)	Commercial rooftop solar, Class 6, "Advanced", ($/MWh)
2023	30 ($1.04/W)	56 ($1.40/W)
2027	22 ($0.80/W)	38 ($1.01/W)
2035	16 ($0.58/W)	24 ($0.66/W)
2050	12 ($0.47/W)	19 ($0.53/W)

Q. WILL THE COSTS OF TRANSMISSION UPGRADES REMAIN UNCHANGED OVER THE NEXT 40 YEARS?

A. Yes. The annualized transmission upgrade costs will not change substantially over the asset life of 40 years. The capital cost is amortized at a fixed rate over time. In contrast the cost of commercial rooftop/parking lot solar is steadily converging with the cost of utility-scale solar over time.

Q. IS THE COST OF PRODUCTION OF UTILITY-SCALE SOLAR DEPENDENT ON THE CLINTON 100 kV UPGRADE HIGHER THAN THE COST OF PRODUCTION OF COMMERCIAL ROOFTOP SOLAR?

A. Yes. The $0.50/watt adder for the two of the three solar projects that will interconnect with the Clinton 100 kV transmission line, which represent

77.5 MW of 115 MW of the interconnecting solar capacity identified in the Phase 1 Cluster Study, translates into a solar cost adder of $30/MWh.[28] The average transmission cost adder for all three solar projects is $0.39/watt, which translates into $23/MWh.[29] The high cost of this new Clinton 100 kV transmission capacity means the alternative – smaller-scale, distribution-tied solar – has a lower cost of production. This is true for all years the Clinton 100 kV upgrade will be operational, from 2027 onward, as shown in Table 3.

Table 3. Red zone solar projects reliant on Clinton 100 kV upgrade would be higher cost than 1 MW of distribution-tied solar in all years the upgrade would be operational (2027 and later)

Year	Red zone solar cost + new transmission adder, Clinton 100 kV ($/MWh)	1 MW distribution-tied solar, ($/MWh)
2027	22 + 23 = 45	38
2035	16 + 23 = 39	24
2050	12 + 23 = 35	19

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM TABLE 3?

A. Commercial rooftop/parking lot solar would be a lower-cost alternative to the solar projects that will interconnect to the Clinton 100 kV upgrade project.

[28] Capital recovery factor (CRF) over 40 years for transmission is 0.1349 (this is CRF for $1.883 billion San Diego Gas & Electric 500 kV Sunrise Powerlink greenfield renewable energy transmission line). Annualized transmission cost, 77.5 MW of solar projects = 0.1349 x $39.55 million = $5.34 million/yr. Annual solar generation = 0.258 x 8,760 hr/yr x 77.5 MW_{ac} = 175,156 MWh/yr. Therefore, unit transmission cost adder = $5.34 million/yr ÷ 175,156 MWh/yr = $30/MWh.

[29] 0.1349 x $44.58 million = $6.01 million/yr. Annual solar generation = 0.258 x 8,760 hr/yr x 115 MW_{ac} = 259,909 MWh/yr. Therefore, unit transmission cost adder = $6.01 million/yr ÷ 259,909 MWh/yr = $23/MWh.

Q. SHOULD DEC HAVE CONDUCTED AN ANALYSIS OF A DISTRIBUTED SOLAR ALTERNATIVE, EITHER NEM OR WHOLESALE DISTRIBUTED SOLAR OR BOTH, PRIOR TO PROPOSING THE $90,248,797 CLINTON 100 kV UPGRADE PROJECT?

A. Yes.

Q. SHOULD THE NCUC DIRECT DEC TO CONDUCT SUCH A DISTRIBUTED GENERATION ALTERNATIVES ANALYSIS AT THIS TIME FOR THE RED ZONE 100 KV TRANSMISSION UPGRADE PROJECTS?

A. Yes.

IV. THE DISTRIBUTED SOLAR ALTERNATIVE TO THE 100 kV TRANSMISSION LINE UPGRADES SHOULD HAVE BEEN EVALUATED BY DEC

Q. WHAT WAS PUBLIC STAFF'S CONCERN REGARDING THE CLINTON 100 kV UPGRADE IN THE CARBON PLAN?

A. Public Staff witness Metz specifically recommended against the Clinton 100 kV because it was unclear if, or how much, renewable energy would be added as a result of the Clinton 100 kV upgrade.[30]

[30] Carbon Plan Order, p. 114: "Looking to the original 18 proposed projects, Public Staff witness Metz recommended against construction of DEC Project #4, the Clinton 100 kV line, because there were relatively few generator facilities impacting that line and the relationship between future solar generation and that upgrade is unclear."

Q. DID PUBLIC STAFF EXPRESS CONCERN GENERALLY ABOUT DUKE ENERGY'S 2022 SOLAR PROCUREMENT PLAN?

A. Yes, as Bill Powers had previously pointed out in his testimony in the Carbon Plan,[32] the Public Staff had expressed its concern with the Companies' 2022 Solar Procurement Proposal. This was before the Commission's approval of the Carbon Plan. Public Staff stated that it was uncertain whether the cost of transmission upgrades needed to interconnect large volumes of utility-scale solar would be the least-cost approach to achieve the carbon reduction goals.[33]

Q. DID PUBLIC STAFF EXPRESS CONCERN THAT NO ALTERNATIVES TO THE TRANSMISSION UPGRADES WERE EVALUATED BY DUKE ENERGY?

A. Yes, Public Staff witness Metz acknowledged in his testimony that the Carbon Plan evaluated no alternative to transmission-dependent utility-scale solar projects located in the red zone.[34]

[32] Powers Carbon Plan Testimony, 9/2/22, p. 49: "The Public Staff expressed concern, regarding the Companies' 2022 Solar Procurement Proposal, that the uncertain cost of transmission upgrades necessary to interconnect large volumes of (utility-scale) solar may not result in least-cost compliance with HB 951's carbon reduction goals."

[33] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 & Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 4.

[34] Public Staff (Metz) Testimony, Sept. 2, 2022, p. 39, footnote 22. ". . . I am not aware of the existence of any other alternate analysis that was completed to compare or contrast the line upgrades Duke selected. This does not imply that Duke's solution is not least cost; it is not clear whether there were other alternatives that could have achieved the same mitigation, such as alternate line analysis, non-wires alternatives, etc."

Q. DID THE CARBON PLAN ACKNOWLEDGE A DISTRIBUTED GENERATION ALTERNATIVE TO TRANSMISSION-DEPENDENT UTILITY-SCALE SOLAR PROJECTS?

A. Yes. The Carbon Plan Order accurately describes the alternative in general terms: "… *there will be times when the most cost-effective solution to a constraint on the transmission system is not more transmission, but rather generation assets located near load."*[35] Those "generation assets located near load" can be solar installations on commercial rooftops, solar on commercial parking lots, or smaller utility-scale solar projects interconnected at the distribution grid level.

Q. DID DUKE EVALUATE ALTERNATIVES TO THE CLINTON 100 kV AND LEE AND PIEDMONT 100 kV TRANSMISSION UPGRADES?

A. No.

V. THE NON-RESIDENTIAL NEM SOLAR TARIFF SHOULD BE SUBJECT TO A SEPARATE APPLICATION

Q. DOES DEC PRESENT ANY EVIDENCE THAT THERE IS A COST-SHIFT FROM NON-RESIDENTIAL NEM CUSTOMERS TO OTHER DEC CUSTOMERS?

A. No. Witness Byrd simply describes the basis for the proposed tariff modifications is DEC's desire to "ensure price alignment with system

[35] The Commission's Carbon Plan Order, Docket No. E-100 Sub 179, at p. 121 (December 30, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=7b947adf-b340-4c20-9368-9780dd88107a

utilization and cost causation."[36] There is no evidence presented supporting a claim that the cost to serve existing non-residential NEM customers is resulting in a cost-shift that advantages non-residential NEM customers.

Q. DOES DEC POINT TO ANYTHING BEYOND THE CDRS STAKEHOLDER PROCESS IN ASSERTING THE PROPOSED NEM TARIFF HAD BEEN VETTED IN SOME WAY?

A. No. Witness Byrd states only that "in aggregate, these changes were discussed during the CRDS (informal stakeholder process)." The discussion of proposed tariff changes with stakeholders of widely varying knowledge levels in no way can substitute for a formal and rigorous application proceeding.

Q. HAS NCSEA ALREADY PROVIDED A DETAILED CRITIQUE OF DUKE ENERGY'S PROPOSAL NON-RESIDENTIAL NEM TARIFF REVISIONS AND CALLED FOR AN APPLICATION TO BE FILED?

A. Yes. NCSEA, in its June 9, 2023 Proposed Order in the DEP General Rate Case regarding the proposed revisions to the DEP non-residential NEM tariff,[37] points out the lack of supporting evidence for the proposed tariff revisions and calls for DEP to file a separate application regarding the proposed revisions. NC WARN adopts the NCSEA June 9, 2023 Proposed

[36] DOCKET NO. E-7, SUB 1276, Direct Testimony of Jonathan L. Byrd, January 19, 2023, p. 20.
[37] NCSEA, DEP Docket No. E-2, Sub 1300, Partial Proposed Order of NCSEA, June 9, 2023.

Order by reference in this testimony and calls for a separate DEC application that would address the proposed revisions to the non-residential NEM tariff.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.