

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1214

In the Matter of:)
Application by Duke Energy Carolinas, LLC,) DIRECT TESTIMONY OF
for Adjustment of Rates and Charges) WILLIAM E. POWERS ON
Applicable to Electric Utility Services in) BEHALF OF NC WARN
North Carolina.)

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is William E. Powers, P.E. My business address is Powers Engineering,
3 4452 Park Blvd., Suite 209, San Diego, CA 92116.

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

5 A. My employer is Powers Engineering. I am the founder and principal of the
6 company.

7 **Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND**
8 **EDUCATIONAL BACKGROUND.**

9 A. I am a consulting and environmental engineer with over 35 years of experience in
10 the fields of power plant operations and environmental engineering. I have
11 worked on the permitting of numerous combined cycle, peaking gas turbine,
12 micro-turbine, and engine cogeneration plants, and am involved in siting of
13 distributed solar photovoltaic (PV) and battery storage projects. I have been an
14 expert witness in high voltage transmission application proceedings in California,
15 Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and

1 battery storage on electric distribution systems for multiple clients. I began my
2 career converting Navy and Marine Corps shore installation projects from oil
3 firing to domestic waste, including wood waste, municipal solid waste, and coal,
4 in response to concerns over the availability of imported oil following the Arab
5 oil embargo in the 1970's.

6 I authored "San Diego Smart Energy 2020" (2007) and "(San Francisco)
7 Bay Area Smart Energy 2020" (2012), and have written articles on the strategic
8 cost and reliability advantages of local solar over large-scale, remote,
9 transmission-dependent renewable resources. I have a B.S. in mechanical
10 engineering from Duke University, an M.P.H. in environmental sciences from
11 UNC – Chapel Hill, and am a registered professional engineer in California and
12 Missouri.

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

16 A. Yes. I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0,
17 Application of NTE Carolinas II, LLC for a Certificate of Public Convenience
18 and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in
19 Rockingham County, North Carolina. I have also offered affidavit testimony and
20 reports to this Commission in prior dockets, such as Docket No. E-2, Sub 1089.
21 Further, I have offered testimony before other utilities commissions across the
22 country, such as the commissions in California, Missouri, and Wisconsin.

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

3 A. The purpose of my testimony is: 1) to address the need for the Commission to
4 reject the Grid Improvement Plan (“GIP”) capital investment program as
5 unreasonable, and 2) to contest cost recovery by DEC for the natural gas
6 conversion projects at the Belews Creek and Cliffside coal-fired power plants.

7 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

8 A. The remainder of my testimony consists of two parts. Part I will address the
9 reasons why the Commission should reject the GIP as unreasonable. Part II will
10 discuss the reasons why the Commission should reject cost recovery for the
11 natural gas conversion projects at Belews Creek and Cliffside.

12 **I. THE GIP SHOULD BE REJECTED**

13 **Q. WHY ARE YOU ADVOCATING THE COMMISSION REJECT COST**
14 **RECOVERY OF THE GIP?**

15 A. Duke Energy Carolinas LLC (“DEC” or “Duke Energy”) has proposed to spend
16 over \$2.3 billion over three years on its GIP capital projects – many of which
17 Duke Energy and the Commission have identified as indistinguishable from
18 traditional spend transmission and distribution (T&D) projects¹ – with no formal
19 application(s) or associated evidentiary processes to evaluate the reasonableness
20 of the proposed expenditures or potential alternatives that negate the need for
21 these proposed expenditures.

¹ DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, pp. 127-150.

1 **Q. WHAT IS THE SCOPE OF THE GIP?**

2 A. Duke Energy lists eighteen separate elements to the GIP, as shown in Table 1,
3 totaling \$2,319.2 million. The most costly single cost element is “Self-Optimizing
4 Grid,” with a capital expenditure of \$722.5 million shared between DEC and
5 Duke Energy Progress LLC (“DEP”). Ten of these eighteen GIP elements have
6 capital budgets in excess of \$100 million.

7 **Table 1. Elements and Budgets for 2020-2022 GIP Programs²**

GIP Program	DEC Budget, \$ millions	DEP Budget, \$ millions	Total Expenditure, \$ millions
Physical & Cyber Security	65.1	68.7	133.8
Self-Optimizing Grid	420.1	302.4	722.5
Integrated Volt/VAR Control	206.7	10.0	216.7
Hardening & Resiliency	102.5	31.3	133.8
Targeted Undergrounding	59.8	54.7	114.5
Energy Storage (*)	56.5	72.5	129.0
Transformer Retrofit	8.3	109.7	118.0
Long Duration Interruptions	11.3	15.8	27.1
Transformer Bank Replacement	33.7	82.7	116.4
Oil Breaker Replacement	115.6	84.7	200.3
Enterprise Communications	103.7	108.1	211.8
Distribution Automation	115.4	78.9	194.3
System Intelligence	62.7	23.7	86.4
Enterprise Applications	17.0	10.8	27.8
ISOP	4.1	2.5	6.6
DER Dispatch	4.5	2.9	7.4
Electric Transportation (*)	38.2	25.3	63.5
Power Electronics	0.7	1.1	1.8
Total			2,319.2

8 (*): Duke Energy excludes Energy Storage and Electric Transportation projects from the GIP total.

9 **Q. OTHER THAN DUKE ENERGY’S OWN INTERNAL ANALYSIS AND**
10 **STAKEHOLDER WORKSHOPS, HAS MORE FORMAL VETTING OF**
11 **THE GIP OCCURRED?**

² DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, Exhibit 10, pdf p. 158.

1 A. No. Duke Energy witness Oliver stated “DE Carolinas’ Grid Improvement Plan
2 was developed through a comprehensive analysis of the trends affecting our
3 business in the state and the tools to best address those trends in a cost-effective
4 and timely manner.” The stakeholder workshops are essentially sales
5 presentations by Duke Energy to stakeholders, many of whom have no technical
6 background in the provision of electric power, on the benefits of the GIP. There
7 has been no formal Commission process to probe whether the alleged benefits are
8 real, whether the benefits justify the costs, and whether alternatives could achieve
9 the same objectives at less cost.

10 **Q. IS IT YOUR POSITION THAT THE STAKEHOLDER WORKSHOPS**
11 **SPONSORED BY DUKE ENERGY AT THE DIRECTION OF THE**
12 **COMMISSION ARE INSUFFICIENT REVIEW OF THE SCOPE AND**
13 **COST OF THE GIP?**

14 A. Yes. The high cost of the GIP alone, about \$2.3 billion in capital expenditures
15 over three years between DEC and DEP,³ is sufficient by itself to mandate an
16 additional rigorous review to protect ratepayers. The GIP as proposed also
17 presumes that there is only one pathway to grid modernization and grid
18 hardening, with no assessment of alternatives that may be much less costly and
19 achieve the stated goals more effectively.

20 **Q. DOES DUKE ENERGY INDICATE ITS TRANSMISSION AND**
21 **DISTRIBUTION GRID IN NORTH CAROLINA IS SAFE AND**
22 **RELIABLE WITHOUT GIP EXPENDITURES?**

³ Ibid.

1 A. Yes. Duke Energy Witness Oliver states that “Our (transmission and distribution)
2 system has performed well, and we have continued to provide safe, reliable, and
3 affordable electric service to our customers.”⁴ In its 2018 general rate case, Duke
4 Energy Witness Simpson “acknowledged that the grid has evolved over decades,
5 and is more hardened today in terms of quality of design than it used to be.”⁵
6 Witness Simpson also testified that the company’s reliability metrics typically
7 vary from year to year, and conceded that DEC actually saw an improving trend
8 from 2003 to 2012 without the implementation of a Power Forward-type program
9 or a rider.⁶ This Duke Energy testimony makes clear that the company’s
10 traditional expenditure levels on transmission and distribution, without GIP, are
11 adequate to provide safe and reliable transmission and distribution service.

12 **Q. CAN YOU GIVE AN EXAMPLE OF WHERE DUKE ENERGY**
13 **PRESUMES WITHOUT ANALYSIS THAT THERE IS ONLY ONE**
14 **APPROACH AVAILABLE TO THE IDENTIFIED DEFICIENCY THAT**
15 **GIP IS INTENDED TO RESOLVE?**

16 A. Yes. An example is the presumption by Duke Energy that targeted
17 undergrounding is the only solution to further reduce outages caused by conductor
18 contact with vegetation. Duke Energy identifies the benefits of targeted
19 undergrounding as: significantly reduce outages, minimize momentary

⁴ DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 20.

⁵ DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 130.

⁶ Ibid, p. 132.

1 interruptions, restore power faster, eliminate tree trimming in hard-to-access
2 areas.⁷

3 Duke Energy acknowledges that vegetation contact is responsible for 20 to
4 30 percent of outages.⁸ However, the company implies that its vegetation
5 management program is as good as it can be, and therefore presumptively no
6 further vegetation management improvement is possible: “For the outages that
7 occur because of trees inside the right-of-way, even a perfectly executed
8 integrated vegetation management plan will not bring this number down to zero
9 but instead will only help minimize vegetation outages.”⁹ Duke Energy also
10 asserts that 50 percent of the vegetation outages are caused by trees located on
11 private property outside its right-of-way and that it does not have the ability to
12 address these trees.¹⁰ Based on this information, Duke Energy makes the
13 conclusory statement that “Drastic clear cutting and going onto customer property
14 and cutting down live trees via condemnation or negotiating with customers for
15 rights on their property is also impractical and not cost effective.”¹¹ This assertion
16 then introduces the alleged benefits of targeted undergrounding with the statement
17 that “programs such as Targeted Undergrounding . . . can be effectively used to

⁷ DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pdf p. 566.

⁸ Ibid, p. 7. “This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system.”

⁹ Ibid, p. 27.

¹⁰ Ibid, p. 27.

¹¹ Ibid, pp. 27-28.

1 address vegetation outages caused by trees outside of the right-of-way.”¹² Duke
2 Energy proposes to spend \$114.5 million on targeted undergrounding projects.¹³

3 **Q. IS DUKE ENERGY’S CONCLUSORY STATEMENT ABOUT THE**
4 **IMPRACTICALITY OF MORE EFFECTIVE VEGETATION**
5 **MANAGEMENT A SUFFICIENT BASIS TO JUSTIFY A \$114.5 MILLION**
6 **TARGETED UNDERGROUNDING CAPITAL EXPENDITURE?**

7 A. No. Duke Energy has made clear that a primary objective of the GIP is to increase
8 shareholder value by accelerating the tempo of capital projects.¹⁴ In this context,
9 the company proposes \$114.5 million in capital expenditure on targeting
10 undergrounding. The estimated cost of a distribution line overhead-to-
11 underground conversion is more than \$2 million per mile in urban and suburban
12 areas.¹⁵ Based on this undergrounding cost-per-mile, Duke Energy will
13 underground about 60 miles of distribution line in this GRC cycle.

14 Vegetation management is also a tool used by Duke Energy to minimize
15 outages on overhead lines. As noted by Witness Oliver, the company has
16 established the 5/7/9 Plan vegetation management program in 2013.¹⁶ An

¹² Ibid. p. 28.

¹³ See, *supra*, Table 1.

¹⁴ DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 129. Duke Energy Witness Fountain also admitted that Power Forward is part of Duke Energy’s corporate policy intended, as quoted in a Duke investor earnings call, “to drive 4 to 6 percent earnings growth.”

¹⁵ Pacific Northwest National Laboratory, *Electricity Distribution System Baseline Report*, July 2016, p. 40. See:

<https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf>.

¹⁶ DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 24. “Duke Energy’s . . . tree-trimming cycle with targeted trim dates by classification include(es) old-urban 5-year cycle, mountain 7-year cycle, and other 9-year cycle, otherwise referred to by the Company as the 5/7/9 Plan.”

1 improved vegetation management program, more frequent than the old-urban 5-
2 year cycle, on the estimated 60 miles of overhead distribution lines that would
3 otherwise be undergrounded by Duke Energy may be able to achieve the same
4 level of outage reduction projected for undergrounding at a fraction of the cost.

5 An improved vegetation management program option should have been
6 considered to assure that any expenditures on targeted undergrounding are just
7 and reasonable for ratepayers.

8 **Q. ARE THERE REASONABLE AND PRACTICAL ALTERNATIVES TO**
9 **DEC'S UNDERGROUNDING PLAN?**

10 A. Yes. It would be practical and less costly to put battery storage in every home
11 along a proposed distribution line undergrounding route. Green Mountain Power
12 ("GMP"), a Vermont investor-owned utility, implemented a virtual power plant
13 ("VPP") in 2017, approved by the Vermont Public Utility Commission, consisting
14 of aggregating and dispatching up to 2,000 residential Tesla Powerwall™ battery
15 storage units.^{17,18} GMP customers participating in this program have the option to
16 purchase the Powerwall™ for a one-time cost of \$1,500 or \$15 per month over
17 ten years.¹⁹ The first phase of this project, consisting of 500 Powerwall™ units,
18 saved GMP more than \$500,000 over several days during a 2018 summer heat

¹⁷ The Tesla Powerwall™ has a discharge capacity of 5 kilowatts (kW) continuous and a storage capacity of 13.5 kW-hours. See: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%20AC_Datasheet_en_northamerica.pdf.

¹⁸ Green Mountain Power, *Notification - Tesla Powerwall Grid Transformation Innovative Pilot*, submitted to Vermont Public Utility Commission, July 31, 2017. See: <http://apps.psc.wi.gov/pages/viewdoc.htm?docid=364977>.

¹⁹ *Ibid*, p. 2.

1 wave.²⁰ Assuming the presence of a comparable program in Duke Energy North
2 Carolina territory, it would cost about \$300,000 per mile to equip every home in a
3 North Carolina neighborhood with a Tesla Powerwall™.²¹ \$300,000 per mile to
4 assure reliability during outages in every home along a distribution line pathway
5 is a small fraction of the more than \$2 million per mile for an overhead-to-
6 underground distribution line conversion along the same route. The home battery
7 storage option is an example of alternatives to the undergrounding capital budget
8 that have not been examined or deployed by Duke Energy.

9 **Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF \$133.8**
10 **MILLION FOR “HARDENING AND RESILIENCY.” WHAT IS**
11 **HARDENING AND RESILIENCY?**

12 A. The company defines hardening and resiliency capital projects as “retrofitting
13 transformers to eliminate common outage causes, replacing aged or deteriorating
14 cable and conductors, and providing back feed capability to vulnerable
15 communities.”²² However, Duke Energy also acknowledges that “. . . energy
16 storage solutions may offer more cost-effective solution(s) for improving
17 reliability and managing costs.”²³ Witness Oliver includes a description of the Hot

²⁰ Utility Dive, *Tesla batteries save \$500K for Green Mountain Power through hot-weather peak shaving*, July 23, 2018. See: <https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/>.

²¹ Assume each home has a street-front property length of 50 feet. Therefore, there are about 100 homes per mile on each side of the street (5,280 feet per mile ÷ 50 feet per home = 105.6 homes per mile per side of street), or about 200 homes per mile total. 200 homes/mile × \$1,500/home = \$300,000 per mile. This cost does not include homeowner investment in an associated solar power system.

²² DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 131.

²³ DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pdf p. 109.

1 Springs, NC microgrid project as an example of Duke Energy using battery
2 storage and solar power to substitute for building a redundant line to provide back
3 feed capability to a vulnerable community.²⁴ Notably, the company filed an
4 application for a certificate of public convenience and necessity to build the Hot
5 Springs microgrid project.²⁵ However, there is no discussion in Witness Oliver's
6 testimony as to whether the battery storage microgrid approach is less costly than
7 building redundant lines to serve vulnerable communities, and therefore should be
8 the preferred method of protecting these vulnerable communities.

9 **Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF \$722.5**
10 **MILLION ON THE "SELF-OPTIMIZING GRID." WHAT IS A SELF-**
11 **OPTIMIZING GRID?**

12 A. Duke Energy proposes to spend \$722.5 million on Self-Optimizing Grid
13 technologies. The company states that "(Self-Optimizing Grid) capabilities are
14 enabled by installing automated switching devices to divide circuits into
15 switchable segments that will serve to isolate faults and automatically reroute
16 power around trouble areas which call for expanding line and substation capacity
17 to allow for two-way power flow and creating tie points between circuits. The
18 IVVC (Integrated Volt/Var Control) program leverages the grid improvements
19 from the self-optimizing technology and adds remotely-operated substation and

²⁴ Duke Energy Progress, *Application for Certificate of Public Convenience and Necessity - Hot Springs Microgrid Solar and Battery Storage Facility*, Docket No. E-2, Sub 1185, October 8, 2018, p. 7. Hot Springs is a remote town of 500 people in the Appalachian Mountains served by a single distribution line that is subject to frequent outages. Duke Energy plans to install approximately 3 MW of solar power and 4 megawatt-hours (MWh) of lithium battery storage and configure circuits to allow Hot Springs to isolate from the grid as needed, known as "islanding," when grid power is unavailable.

²⁵ Ibid.

1 distribution line devices such as regulator and capacitor controllable field devices
2 that enable a grid operator to lower voltage as a way to reduce peak demand,
3 thereby reducing the need to generate or purchase additional power at peak prices
4 (peak shaving) or to operate in a conservation mode during periods of more
5 typical electricity demand in order to reduce overall energy consumption and
6 system losses.”²⁶ Duke Energy then makes the conclusory statement, with no
7 evidentiary support, that the “Self-Healing Grid . . . ensures many issues on the
8 grid can be isolated and customer impacts are limited to hundreds versus
9 thousands.”²⁷ This statement implies that outages will be reduced by 90 percent or
10 more (“limited to hundreds versus thousands”), but no evidence is offered to
11 support or clarify the meaning. In a single sentence, Duke Energy mixes talk of
12 switching devices to isolate faults with expanding line and substation capacity to
13 allow for two-way power flow. There is no analysis of alternatives that might
14 achieve the same distribution grid reliability improvement at less cost to
15 ratepayers.

16 **Q. IS EXPANSION OF LINE AND SUBSTATION CAPACITY NECESSARY**
17 **TO ENABLE TWO-WAY POWER FLOW CAUSED BY HIGH LEVELS**
18 **OF DISTRIBUTED ENERGY RESOURCES (AKA ROOFTOP SOLAR)?**

19 A. No. Installing rooftop solar with battery storage in homes and businesses can
20 achieve the same purpose. An October 2017 study commissioned by the
21 California Public Utilities Commission (“CPUC”), *Customer Distributed Energy*

²⁶ DOCKET NO. E-7, SUB 1214, Duke Energy Carolinas, LLC Jay Oliver Direct Testimony, September 30, 2019, pp. 38-39.

²⁷ Ibid, p. 38.

1 *Resources Grid Integration Study - Residential Zero Net Energy Building*
2 *Integration Cost Analysis*,²⁸ examined the degree to which grid upgrades would
3 be necessary to absorb rooftop solar flows in neighborhoods where all homes
4 have rooftop solar. The context of the 2017 study is the California mandate that
5 all new residences built in 2020 or later are zero net energy homes with rooftop
6 solar.²⁹ The study was in effect a “worst case” assessment of the existing grid’s
7 ability to absorb distributed solar inflows when all homes on a circuit are
8 generating solar power and potentially exporting some or all of that solar power to
9 the grid at the same time.

10 **Q. IS IT YOUR POSITION THAT ADDING SOLAR AND BATTERY**
11 **STORAGE AT HOMES AND BUSINESSES ACHIEVES THE SAME END**
12 **WITHOUT THE POTENTIAL FOR STRANDED INVESTMENTS IN**
13 **GRID OPTIMIZATION?**

14 A Yes. Distribution circuits are typically designed to accommodate double or more
15 of the expected peak load on the circuit.³⁰ The basis for this is to provide
16 sufficient capacity to ensure each circuit can serve as a backup source of power to
17 an adjacent circuit in case of an outage on the adjacent circuit. In this context, the
18 2017 California study examined rooftop solar inflows (i.e. two-way flow) up to
19 160 percent of the base case peak load of the distribution circuit being analyzed.

²⁸ DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017. “This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020),” p. vii.

²⁹ New York Times, *California Will Require Solar Power for New Homes*, May 9, 2018:

<https://www.nytimes.com/2018/05/09/business/energy-environment/california-solar-power.html>.

³⁰ The thermal rating of the conductors determines the maximum power flow.

1 The study determined that simple steps, such as use of “smart” solar inverters and
2 good distribution of the solar systems along the circuit, could substantially
3 increase the capacity of the circuit to absorb solar inflows with little or no cost.

4 The 2017 study also determined that, without battery storage,
5 incrementally more extensive grid upgrades would potentially be necessary,
6 including regulator control upgrades, re-close blocking, reconductoring of
7 overloaded circuit sections, and/or additional voltage regulators, to address grid
8 reliability issues. However, the addition of battery storage with the rooftop solar
9 would negate the need for progressively more expensive grid optimization
10 upgrades. The report states that “. . . energy storage could be deployed to mitigate
11 all violations on the circuit rather than deploying other measures at lower
12 penetrations that would later become redundant.”³¹ In this case, Duke Energy is
13 proposing grid optimization measures that will become redundant if battery
14 storage is integrated with rooftop solar. The deployment of battery storage with
15 rooftop solar systems is projected to rapidly become a standard industry
16 practice.³²

17 The 2017 study concludes its assessment of the grid reliability value of
18 battery storage stating “. . . (battery storage) could prove much more cost-
19 effective in the long run particularly given the other functions that are available

³¹ DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017, p. xv. “This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020),” p. vii.

³² Greentech Media, *10 Rooftop Solar and Storage Predictions for the Next Decade*, January 3, 2020: <https://www.greentechmedia.com/articles/read/10-rooftop-solar-and-storage-predictions-for-the-next-decade>.

1 from distributed energy storage systems. If energy storage was implemented at the
2 buildings or circuits . . . , then the associated integration costs identified in this
3 study would be negated.” In sum, if an appropriate capacity of battery storage is
4 included with solar installations in neighborhoods where 100 percent of the
5 homes have rooftop solar, no additional “grid optimization” would be necessary
6 to the existing distribution grid.

7 **Q. IS ANOTHER STATE EXPECTING TO ADD ABOUT 3,000 MW OF**
8 **RESIDENTIAL AND COMMERCIAL BATTERY STORAGE FOR**
9 **ABOUT THE SAME COST AS DUKE ENERGY’S \$722.5 MILLION**
10 **SELF-OPTIMIZING GRID CAPITAL BUDGET?**

11 A. Yes. California senate bill SB 700 was signed into law in late September 2018
12 and is expected to add, with an incentive budget of \$830 million, up to 3,000 MW
13 of behind-the-meter residential and commercial storage in California by 2026.³³

14 **Q. DUKE ENERGY INDICATES THAT THE \$216.7 MILLION SPENT ON**
15 **IVVR WILL REDUCE DISTRIBUTION SYSTEM PEAK BY**
16 **APPROXIMATELY 1.1 PERCENT.³⁴ \$206.7 MILLION OF THIS**
17 **CAPITAL BUDGET IS SLATED TO BE SPENT IN DEC SERVICE**
18 **TERRITORY. IS THIS REDUCTION WORTH \$206.7 MILLION?**

19 A. No. Customer-owned solar with battery storage systems could achieve the same
20 objective at no cost to non-solar ratepayers and at about 40 percent of the cost of

³³ Greentech Media, *California Passes Bill to Extend \$800M in Incentives for Behind-the-Meter Batteries*, August 31, 2018, <https://www.greentechmedia.com/articles/read/california-passes-bill-to-extend-incentives-for-behind-the-meter-batteries#gs.6cxCMs0>.

³⁴ Duke Energy, *North Carolina Grid Improvement Plan – Pre-Read Packet for May 16, 2019 Stakeholder Meeting*, p. 13.

1 Duke Energy's IVVR program. The one-hour peak load in DEC service territory
2 in 2018 was 18,935 MW.³⁵ A one-hour peak load reduction of 1.1 percent = 208
3 MW.³⁶ As previously noted, the cost (to customers) of a 5 kW capacity Tesla
4 Powerwall™ under GMP's VPP program is \$1,500. This equates to 5 MW
5 capacity per \$1.5 million capital investment in residential battery storage.
6 Therefore, 208 MW × (\$1.5 million/5 MW capacity) = \$63 million, or about 30
7 percent of the IVVR program cost of \$206.7 million in DEC service territory. No
8 analysis of the residential battery storage VPP alternative to the IVVR program is
9 included in Duke Energy's testimony.

10 **Q. DUKE ENERGY STATES THAT THE SELF-OPTIMIZING GRID**
11 **INVESTMENT WILL INCREASE CUSTOMER SOLAR CAPACITY TO**
12 **835 MW.³⁷ IS THE SELF-OPTIMIZING GRID NECESSARY TO**
13 **ACHIEVE A CUSTOMER SOLAR CAPACITY OF 835 MW?**

14 A. No. Duke Energy has far more than 835 MW of solar capacity on its North
15 Carolina distribution systems with no upgrades to the distribution grid(s). The
16 Department of Energy has sponsored numerous utility studies of the solar
17 capacity of distribution systems. One study involved the Dominion Virginia
18 Power (DVP) distribution system.³⁸ DVP evaluated 14 representative distribution
19 feeders from an overall distribution feeder population of 1,813 in its service

³⁵ DEC 2018 FERC Form 1, May 29, 2019, p. 401b. The DEC 2018 FERC Form 1 dated May 29, 2019 is publicly available and can be downloaded at <https://elibrary.ferc.gov/IDMWS/search/fercgensearch.asp>.

³⁶ 18,935 MW x 0.011 = 208 MW.

³⁷ Duke Energy, *North Carolina Grid Improvement Plan – Pre-Read Packet for May 16, 2019 Stakeholder Meeting*, p. 11. “SOG increases hosting capacity from approximately 496 MW to 835 MW.”

³⁸ An affiliated company of DVP, Dominion North Carolina, is regulated by NCUC.

1 territory.³⁹ The DVP summer peak load of 15,570 MW is comparable to the 2018
2 DEC and DEP peak loads of 18,935 MW and 15,322 MW,⁴⁰ respectively. DVP
3 evaluated the percentage of thermal rating of the feeder available for solar hosting
4 as upgrades were added. This necessitates understanding the relationship between
5 peak load on the feeder and the thermal rating of the feeder.

6 The feeder thermal rating, meaning the point at which overhead feeders
7 sag excessively due to the high temperature of the conductor or at which
8 underground feeders approach the temperature where the insulation could begin to
9 melt, is typically 2 to 3 times the peak load on the feeder.⁴¹ Conversely, 100
10 percent of peak load is approximately 33 to 50 percent of the feeder thermal
11 rating, depending on the individual feeder. This is an important relationship to
12 understand to interpret the DVP results. The results shown in Figure 1 are for the
13 three feeders selected by DVP for presentation, and assume that smart solar
14 inverters – without battery storage – are utilized to optimize voltage at the point of
15 interconnection between the solar array and the feeder.

16

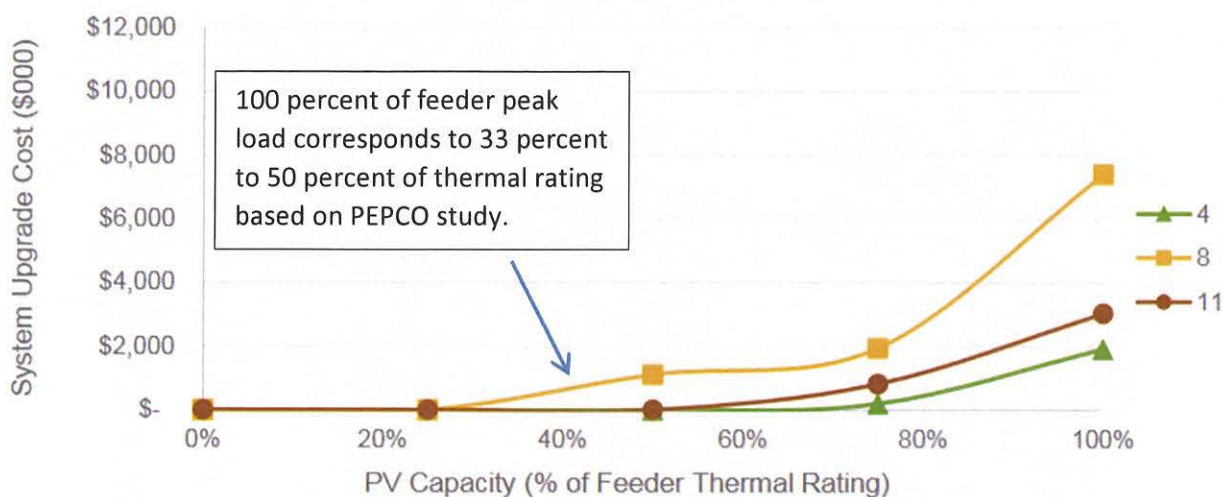
17

³⁹ B. Powers, *North Carolina Clean Path 2025*, August 2017, pp. 73-74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.

⁴⁰ DEP 2018 FERC Form 1, April 12, 2019, p. 401b.

⁴¹ *Ibid.*, B. Powers, *North Carolina Clean Path 2025*, August 2017, Table 30a Increase in Solar Hosting Capacity and Upgrade Cost for Top 12 of 20 PEPCO Feeders Evaluated, p. 72. The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load. See: DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (<https://www.osti.gov/servlets/purl/1229729>).

1 **Figure 1. Cost Versus Improvement in Solar Hosting Capacity for Selected DVP**
 2 **Feeders Assuming Use of Advanced Solar Inverters**
 3 (source: Navigant)⁴²



4
 5 The most representative feeder among the three shown in Figure 1, in the opinion
 6 of Powers Engineering, is Feeder 11. This feeder serves a predominantly
 7 residential load, as do most of the fourteen representative feeders included in the
 8 DVP study. In contrast, Feeder 8 serves a predominantly commercial load and is
 9 representative of only about 1 percent of the 1,813 feeders in the DVP service
 10 territory. Feeder 4 is somewhat of an outlier, representing low voltage (4.16 kV)
 11 and very short (3 miles) feeders. No significant solar hosting upgrade costs are
 12 encountered on Feeder 11 until about 67 percent of the thermal rating is reached,
 13 which equates to 133 to 200 percent of feeder peak load.⁴³ This data implies that
 14 the Duke Energy North Carolina distribution grid, with a peak load of

⁴² B. Powers, *North Carolina Clean Path 2025*, August 2017, Figure 14, p. 74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.

⁴³ DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (<https://www.osti.gov/servlets/purl/1229729>). The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load.

1 approximately 34,000 MW,⁴⁴ could meet that 34,000 MW peak load with
2 distributed solar power – and without battery storage – with little or no upgrading.
3 In contrast Duke Energy presumes, with no analysis, that its base case distributed
4 solar hosting capacity without the Self-Optimizing Grid program is only 496 MW.

5 **Q. IS THE CONSERVATIVE DEFAULT SOLAR CAPACITY OF DEC AND**
6 **DEP DISTRIBUTION FEEDERS ALREADY SIX TIMES HIGHER THAN**
7 **THE GIP SMART GRID OPTIMIZATION TARGET OF 835 MW?**

8 Yes. The default rule-of-thumb for solar capacity on a distribution feeder without
9 any need for study is 15 percent.⁴⁵ Using this rule-of-thumb, the total default “as
10 is” solar hosting capacity of the DEC and DEP North Carolina distribution feeders
11 is in the range of $34,000 \text{ MW} \times 0.15 = 5,100 \text{ MW}$. This is about six times higher
12 than the stated GIP Smart Grid Optimization solar capacity goal of 835 MW.

13 There is no justification for a Smart Grid Optimization solar capacity goal of 835
14 MW and any capital expense justified as necessary to achieve this goal is
15 unreasonable.

16 **II. NATURAL GAS FUEL CONVERSIONS AT BELEWS CREEK**
17 **AND CLIFFSIDE COAL PLANTS**
18

⁴⁴ 18,935 MW (DEC) and 15,322 MW (DEP) = 34,257 MW (non-coincident).

⁴⁵ NREL, *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*, July 2012, p. 1. See: <https://www.nrel.gov/docs/fy12osti/55094.pdf>. “A commonly used rule of thumb in the U.S. allows distributed PV systems with peak powers up to 15% of the peak load on a feeder (or section thereof) to be permitted without a detailed impact study [4]. This necessarily conservative rule has been a useful way to allow many distributed PV systems to be installed without costly and time-consuming distribution system impact studies.”

1 **Q. WHAT IS THE CAPITAL COST AND SCOPE OF THE NATURAL GAS**
2 **CONVERSIONS AT BELEWS CREEK AND CLIFFSIDE COAL**
3 **PLANTS?**

4 A. DEC requests \$278 million in recovery in this rate case for natural gas
5 conversions at Belews Creek and Cliffside.⁴⁶ The 1,120 MW (each) Belews Creek
6 Units 1 and 2⁴⁷ will be capable of burning up to 50 percent natural gas following
7 the conversion.⁴⁸ 825 MW Cliffside Unit 6 will have the capability to burn 100
8 percent natural gas, 100 percent coal or a mix of the two fuels. 530 MW Cliffside
9 Unit 5 will be able to burn a mix of coal and gas that consists of up to 40 percent
10 gas.⁴⁹

11 **Q. ARE THESE BASELOAD PLANTS?**

12 A. No. Belews Creek had a capacity factor of 41 percent in 2018.⁵⁰ Cliffside had a
13 capacity factor of 47 percent in 2018.

14 **Q. WHAT WAS THE PRODUCTION COST AT BELEWS CREEK AND**
15 **CLIFFSIDE IN 2018?**

⁴⁶ Charlotte Business Journal, *Here's how much Duke Energy is seeking to raise utility rates in North Carolina*, September 30, 2019: <https://www.bizjournals.com/charlotte/news/2019/09/30/heres-how-much-duke-energy-is-seeking-to-raise.html>.

⁴⁷ DEC currently plans to complete a conversion at Unit 2 for Belews Creek which is similar to that conversion completed at Unit 1, and therefore, both Units 1 and 2 of Belews Creek will be discussed herein.

⁴⁸ Charlotte Business Journal, *Duke Energy wrapping up \$65M gas co-firing project for its Cliffside coal units*, November 19, 2018: <https://www.bizjournals.com/charlotte/news/2018/11/19/duke-energy-wrapping-up-65m-gas-co-firing-project.html>.

⁴⁹ Ibid.

⁵⁰ DEC 2018 FERC Form 1, May 29, 2019, p. 402 and p. 403.1 (line 12). Belews Creek 2018 generation = 8,021,417 MWh. Cliffside 2018 generation = 5,554,473 MWh. Therefore, Belews Creek 2018 capacity factor = $8,021,417 \text{ MWh} \div (8,760 \text{ hr/yr} \times 2,240 \text{ MW}) = 0.41$. Cliffside 2018 capacity factor = $5,554,473 \text{ MWh} \div (8,760 \text{ hr/yr} \times 1,355 \text{ MW}) = 0.47$.

1 A. The production cost at both Belews Creek and Cliffside was approximately \$40
2 per MWh.⁵¹

3 **Q. DOES BURNING NATURAL GAS IN COAL-FIRED STEAM BOILERS**
4 **FURTHER REDUCE THE ALREADY LOW THERMAL EFFICIENCY**
5 **OF THE PROCESS?**

6 A. Yes. Burning natural gas in steam boilers formerly fired on coal reduces the
7 thermal efficiency of the steam boiler combustion process by 3 to 5 percent.⁵² The
8 coal-fired steam boiler is already a relatively low efficiency power generation
9 process compared to a combined cycle power plant.⁵³

10 **Q. WHAT IS THE PRODUCTION COST OF COMBINED CYCLE UNIT?**

11 A. About \$31/MWh,⁵⁴ or about 25 percent less than the production cost at Belews
12 Creek or Cliffside.

13 **Q. WHAT IS THE PRODUCTION COST OF HYDROELECTRIC UNITS?**

14 A. About \$13/MWh, or about one-third the production cost at Belews Creek or
15 Cliffside.⁵⁵

16 **Q. ARE EXISTING REGIONAL MERCHANT COMBINED CYCLE AND**
17 **HYDROELECTRIC PLANTS AVAILABLE TO SUPPLY DUKE ENERGY**
18 **WITH LOWER-COST POWER THAN POWER FROM BELEWS CREEK**
19 **AND CLIFFSIDE?**

⁵¹ Ibid, p. 402 and p. 403.1 (line 35).

⁵² Power Engineering, *De-Bunking the Myths of Coal-to-Gas Conversions*, Issue 11 and Volume 119, December 2, 2015. See: <https://www.power-eng.com/2015/12/02/de-bunking-the-myths-of-coal-to-gas-conversions/#gref>.

⁵³ 2018 DEC FERC Form 1, May 29, 2019, p. 402 (Belews Creek heat rate = 9,424 Btu/kWh), p. 403.1, (Cliffside heat rate = 9,241 Btu/kWh), p. 403.3 (Buck combined cycle plant heat rate = 7,160 Btu/kWh).

⁵⁴ Ibid, p. 403.3 (Buck combined cycle plant, 698 MW, expenses per net kWh = \$0.0311/kWh – line 35).

⁵⁵ Ibid, p. 406.1 (Cowans Ford hydro plant, 350 MW, expenses per net kWh = \$0.0129/kWh – line 35).

1 A. Yes. I addressed this issue in July 2016 in DOCKET NO. E-2, SUB 1089,
2 Application of Duke Energy Progress, LLC for a Certificate of Public
3 Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled
4 Electric Generation Facility in Buncombe County Near the City of Asheville.⁵⁶
5 The affidavit filed by NC WARN on my behalf in DOCKET NO. E-2, SUB 1089,
6 which affidavit is both accurate and pertinent today, stated that “DEP West has
7 available off-the-shelf hydropower and combined cycle gas turbine options in the
8 region to supply capacity if additional capacity is needed . . . Four Smoky
9 Mountain Hydro units near the North Carolina-Tennessee border have a capacity
10 of 378 MW and produce 1.4 million MWh annually. These units are in the TVA
11 system, which is connected to DEP West by a single 161 KV line from TVA to
12 the substation at the Walters Hydro Plant in DEP West. The power produced by
13 these units is not currently contracted for purchase. . . The underutilized merchant
14 523 MW Columbia Energy combined cycle plant outside of Columbia, SC, built
15 more than a decade ago when the capital cost of combined cycle power
16 construction was lower than it is today, could serve some or all of any need that
17 might arise.” These are examples of lower-cost regional power supplies that could
18 have been contracted in 2016 to avoid substantial Duke Energy capital
19 expenditures on new generation. The same approach should have been used to
20 assess the reasonableness of natural gas conversions at Belews Creek and

⁵⁶ DOCKET NO. E-2, SUB 1089 - Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville, *Affidavit of William E. Powers for NC WARN and The Climate Times*, June 27, 2016.

1 Cliffside. There is currently nearly 50,000 MW of low-cost merchant combined
2 cycle capacity in the PJM regional market,⁵⁷ adjacent to Duke Energy North
3 Carolina territory, potentially available for contracting by Duke Energy to
4 substitute for higher cost production from Belews Creek and Cliffside.⁵⁸ Relying
5 on existing regional lower cost gas and/or hydroelectric resources would have
6 saved Duke Energy ratepayers money and potentially facilitated the permanent
7 shutdown of Belews Creek and Cliffside.

8 **Q. ARE SOLAR WITH BATTERY STORAGE PROJECTS ALREADY**
9 **CAPABLE OF PRODUCING POWER FOR LESS THAN THE \$40/MWH**
10 **PRODUCTION COST AT BELEWS CREEK AND CLIFFSIDE?**

11 A. Yes. Los Angeles Department of Water and Power signed a 25-year contract for
12 the 375 MW Eland solar and battery storage project in September 2019 for just
13 under \$40/MWh.⁵⁹ The project includes four hours of battery storage at rated
14 capacity.⁶⁰ The cost of battery storage capacity continues to decline at a rapid
15 rate.⁶¹

⁵⁷ Monitoring Analytics, LLC, *2019 Quarterly State of the Market Report for PJM: January through March*, May 9, 2019, p. 65. See: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf. As of March 31, 2019, there was 47,591.6 MW of operational combined cycle capacity in PJM.

⁵⁸ U.S. Energy Information Administration, *Natural gas-fired power plants are being added and used more in PJM Interconnection*, October 17, 2018. See:

<https://www.eia.gov/todayinenergy/detail.php?id=37293>. Combined cycle units in PJM generated about 200 million MWh in 2017, at an average capacity factor of about 60 percent.

⁵⁹ PV Magazine USA, *Los Angeles says "Yes" to the cheapest solar plus storage in the USA*, September 10, 2019. See: <https://pv-magazine-usa.com/2019/09/10/los-angeles-commission-says-yes-to-cheapest-solar-plus-storage-in-the-usa/>.

⁶⁰ Ibid.

⁶¹ CNBC, *The battery decade: How energy storage could revolutionize industries in the next 10 years*, December 30, 2019. See: <https://www.cnbc.com/2019/12/30/battery-developments-in-the-last-decade-created-a-seismic-shift-that-will-play-out-in-the-next-10-years.html>.

1 **Q. COULD THE ADDITION OF BATTERY STORAGE TO THE NEARLY**
2 **6,000 MW OF UTILITY-SCALE SOLAR IN NORTH CAROLINA**
3 **ACHIEVE THE SAME OBJECTIVE AS ADDING GAS-FIRING**
4 **CAPABILITY AT THE BELEWS CREEK AND CLIFFSIDE COAL**
5 **PLANTS?**

6 A. Yes. This approach could be used on the nearly 6,000 MW of solar farms in North
7 Carolina⁶² to smooth-out solar generation and provide dispatchable peaking
8 power.

9 **Q. WOULD THIS APPROACH IMPOSE ANY CAPITAL COST BURDEN**
10 **ON DUKE ENERGY RATEPAYERS?**

11 A. No. The cost of battery storage additions would be borne by the third-party
12 owners of the solar facilities. However, Duke Energy has opposed allowing solar
13 facility owners to add battery storage. As noted by NCSEA Witness Tyler Harris,
14 “Duke Energy is proposing unjust and unreasonable barriers to market entry for
15 energy storage resources – particularly with respect to power purchase terms and
16 conditions and interconnection standards – that will wholly obstruct the addition
17 of such resources to the vast majority of installed renewable generating facilities
18 in North Carolina.”⁶³ Duke Energy has spent \$278 million on natural gas
19 conversions at Belews Creek and Cliffside that could have been avoided – and
20 Belews Creek and Cliffside potentially mothballed – by simply allowing existing

⁶² Solar Energy Industries Association, *State Solar Spotlight: North Carolina*, at <https://www.seia.org/sites/default/files/2019-12/North%20Carolina.pdf>.

⁶³ Docket No. E-100, Sub 158, Direct Testimony of Tyler H. Norris on behalf of NCSEA, July 3, 2019, p. 8.

1 solar facilities in North Carolina to add battery storage at their own expense in
2 return for reasonable payment for the added value of the storage capacity. For all
3 of these reasons, the said expenditures at Belews Creek and Cliffside were neither
4 reasonable nor prudent, and DEC's cost recovery requests at those facilities
5 should therefore be denied.

6 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

7 **A. Yes.**

CERTIFICATE OF SERVICE

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

This the 18th day of February, 2020.



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