

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214**

**In the Matter of:
Application of Duke Energy Carolinas,
LLC for Adjustment of Rates and
Charges Applicable to Electric Service
in North Carolina**

) **TESTIMONY OF DENNIS**
) **STEPHENS ON BEHALF OF THE**
) **NORTH CAROLINA JUSTICE**
) **CENTER, NORTH CAROLINA**
) **HOUSING COALITION, NATURAL**
) **RESOURCES DEFENSE COUNCIL**
) **AND SOUTHERN ALLIANCE FOR**
) **CLEAN ENERGY AND THE**
) **NORTH CAROLINA**
) **SUSTAINABLE ENERGY**
) **ASSOCIATION**

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February 18, 2020

TABLE OF CONTENTS

I.	Introduction	1
II.	Preview and Recommendations	3
III.	Historical Context.....	10
IV.	GIP Programs Meriting Approval with Conditions.....	15
V.	GIP Programs Requiring Material Modifications and Conditions to Merit Approval	21
A.	Self-Optimizing Grid.....	22
B.	Transmission Hardening and Resilience (Excluding Flood and Animal Mitigation).....	27
VI.	GIP Programs That Should Be Rejected Due to Lack of Cost Effectiveness/Compliance with Standard Industry Practice.....	29
A.	Targeting Undergrounding	29
B.	Distribution Transformer Retrofits.....	33
C.	Transformer Bank Replacement.....	34
D.	Oil-Filled Breaker Replacement.....	35
E.	Substation Physical Security	37
VII.	GIP Programs That Should Be Rejected Pending Further Evaluation	37
A.	Mission Critical Voice and Data Network Programs	38
B.	Distribution Automation and Transmission System Intelligence Programs	39
VIII.	Summary and Recommendations	40

EXHIBITS

Stephens Exhibit 1: Curriculum Vitae of Dennis Stephens.

Stephens Exhibit 2: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-4, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 3: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 4-6, Docket No. E-7, Sub 1214, January 21, 2020.

Stephens Exhibit 4: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et. al.*, Data Request 3-32, Docket No. E-7, Sub 1214, January 2, 2020.

Stephens Exhibit 5: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-33, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 6: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 8-34, Docket No. E-7, Sub 1214, February 10, 2020.

Stephens Exhibit 7: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 5-40, Docket No. E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 8: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 2-4, Docket No. E-7, Sub 1214, January 9, 2020.

Stephens Exhibit 9: Duke Energy Carolinas Response to North Carolina Justice Center, *et. al.*, Data Request 2-19, Docket No. E-7, Sub 1214, November 25 2019.

I. Introduction

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

2 A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Ste.
3 130, Evergreen, Colorado, 80439.

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

5 A. I am an independent consultant. I collaborate frequently with Paul Alvarez, who
6 is also testifying in this docket, and his firm, the Wired Group, on behalf of clients
7 in distribution utility regulatory proceedings on matters of electric distribution
8 grid planning, investment, operations, reliability, and distributed energy resource
9 accommodation.

10 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL**
11 **BACKGROUND.**

12 A: After graduating from the University of Missouri with a bachelor's degree in
13 Electrical Engineering, I began work for Xcel Energy (then Public Service
14 Company of Colorado) as an electrical engineer in distribution operations. In a
15 series of electrical engineering and management roles of increasing responsibility,
16 I gained experience in distribution planning, operations, and asset management,
17 and the innovative use of technology to assist with these functions. Positions I
18 have held over the years have included Director, Electric and Gas Operations for
19 the City and County of Denver Colorado; Director, Asset Strategy; and Director,
20 Innovation and Smart Grid Investments.

21 In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™
22 demonstration project in Boulder, Colorado, the first of its kind at the time,

1 covering 46,000 ratepayers. I developed the technical foundations for the project,
2 including the development of all concepts presented to the Xcel Energy Executive
3 Committee for project approval, and including the negotiations with technology
4 vendors on their contributions to the project. As Director of Utility Innovations
5 for Xcel Energy, I also worked with many software providers, including ABB,
6 IBM, and Siemens, helping them develop their distribution automation ideas into
7 practical software applications of value to grid owner/operators. I retired from
8 Xcel Energy in 2011, and now consult for the Wired Group part-time.

9 **Q HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH**
10 **CAROLINA UTILITIES COMMISSION?**

11 A. No.

12 **Q. HAVE YOU TESTIFIED BEFORE OTHER STATE UTILITY**
13 **REGULATORY COMMISSIONS?**

14 A. Yes. I have testified jointly with Witness Alvarez in three rate cases before the
15 California Public Utilities Commission. I testified regarding the appropriateness
16 of multi-billion-dollar grid modernization proposals by Southern California
17 Edison and Pacific Gas and Electric. I also critiqued Indianapolis Power and
18 Light's \$1.2 billion Grid Improvement Plan before the Indiana Utility Regulatory
19 Commission and testified jointly with Witness Alvarez in cases regarding
20 distribution grid planning process development in Michigan and New Hampshire.
21 I have also supported the Wired Group in client projects not involving testimony,
22 including one in South Carolina regarding Duke Energy's Grid Modernization

1 Plan,¹ and a similar paper on Dominion’s Grid Transformation Plan.² (I note the
2 Virginia SCC largely rejected Dominion’s Grid Transformation Plan.)³ My full
3 CV is provided as Exhibit DS-1 to this testimony.

4 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

5 A. I am testifying on behalf of the North Carolina Justice Center, the North Carolina
6 Housing Coalition, the Natural Resources Defense Council, and the Southern
7 Alliance for Clean Energy (collectively, “NCJC et al.”) and the North Carolina
8 Sustainable Energy Association (“NCSEA”). My testimony critiques the Grid
9 Improvement Plan (“GIP”) and associated cost-benefit analyses Duke Energy
10 Carolinas, LLC (“DEC”) presents in this case.⁴

I. Preview and Recommendations

11 **Q. PLEASE PROVIDE A PREVIEW OF YOUR TESTIMONY AND**
12 **RECOMMENDATIONS IN THIS PROCEEDING.**

13 A. My testimony begins with context, describing typical distribution planning
14 processes utilities have employed for decades. I also provide historical data
15 indicating that Duke Energy’s reliability has deteriorated markedly in recent years
16 despite grid investment growth far exceeding peak demand growth. My
17 testimony then identifies multiple deficiencies in the design, technical

¹ Alvarez P and Stephens D. *Modernizing The Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers*. Paper prepared for GridLab. Jan. 31, 2019.

² Alvarez P and Stephens D. *Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders*. October 5, 2018.

³ Final Order RE: Petition of Virginia Electric and Power Company. Virginia State Corporation Commission Docket No. PUR-2018-00100 (January 17, 2019).

⁴ DEC and Duke Energy Progress, LLC (“DEP”) have each filed the GIP in their concurrent respective rate cases. Since the GIP is, for the most part, common to both DEP and DEC and incorporates territory-overlapping programs and proposed investments, I will be referring to DEC and DEP, collectively, as “Duke Energy” throughout my testimony in reference to the GIP proposal.

1 justification, and cost-effectiveness of many GIP programs, and identifies a
2 complete lack of justification for others. These illustrate the opportunity for a
3 transparent, stakeholder-engaged distribution planning and capital budgeting
4 process to improve the value delivered to North Carolina ratepayers,
5 communities, and the environment by distribution grid investments.

6 **Q. WHAT IS YOUR PRIMARY RECOMMENDATION TO THE**
7 **COMMISSION?**

8 A. My primary recommendation is for the Commission to reject Duke Energy’s GIP
9 and establish a proceeding to develop such a process for use in developing future
10 distribution plans and capital budgets that better align the needs of stakeholders
11 and utilities. Witness Alvarez’s testimony provides an outline for such a process,
12 and additional justification for the same recommendation.

13 **Q. IN THE EVENT THAT THE COMMISSION DOES NOT ACCEPT YOUR**
14 **PRIMARY RECOMMENDATION, DO YOU HAVE A SECONDARY**
15 **RECOMMENDATION?**

16 A. Yes. My testimony provides a secondary, alternative recommendation, wherein
17 the Commission evaluates each GIP program independently. This part of my
18 testimony examines individual GIP programs and sub-components in detail,
19 providing valuable, objective information regarding the design and justification
20 (or lack thereof) for each GIP program. I categorize GIP programs into groups of
21 similar merit. In the event the Commission rejects my primary recommendation, I
22 hope these “merit groupings” will serve as a set of secondary recommendations to
23 inform Commission decisions. The merit groups and programs are presented in
24 Table 1, summarized below, and explained in detail in my testimony.

1 *Table 1: Summary of GIP Programs/Sub-components By Merit*

Program/Subcomponent	Capital \$ per Oliver Exh. 10 (in millions)	Suggested Adjustments	Capital \$ per NCJC/NCSEA If GIP Not Rejected
Merits Approval w/Conditions	\$ 374.16	\$ -	\$ 374.16
Integrated Volt/VAr Control	\$ 216.66	\$ -	\$ 216.66
Transmission H&R -- Flood & Animal Mitigation Components	\$ 13.18	\$ -	\$ 13.18
Long Duration Interruption/High Impact Sites	\$ 27.10	\$ -	\$ 27.10
Enterprise Applications/ISOP Software/DER Software	\$ 41.94	\$ -	\$ 41.94
Cyber and Physical Security, excluding substation physical	\$ 23.04	\$ -	\$ 23.04
Enterprise Comm's excluding new data and voice networks	\$ 52.24	\$ -	\$ 52.24
Merits Approval w/Material Modifications & Conditions	\$ 843.05	\$ (336.80)	\$ 506.25
Self-Optimizing Grid/Advanced Dist Mgmt System	\$ 722.48	\$ (336.80)	\$ 385.67
Transmission H&R (DER Capacity Upgrades ONLY)	\$ 120.57	\$ -	\$ 120.57
Merits Rejection	\$ 659.95	\$ (659.95)	\$ -
Targeted Undergrounding	\$ 114.54	\$ (114.54)	\$ -
Distribution Transformer Retrofit	\$ 118.02	\$ (118.02)	\$ -
Transformer Bank Replacement	\$ 116.39	\$ (116.39)	\$ -
Oil-Filled Breaker Replacement	\$ 200.29	\$ (200.29)	\$ -
Substation Perimeter Security	\$ 110.71	\$ (110.71)	\$ -
Merits Rejection Pending Further Evaluation	\$ 440.27	\$ (440.27)	\$ -
Enterprise Comm's, new data & voice (tech/econ make/buy analyses)	\$ 159.58	\$ (159.58)	\$ -
Distribution Automation (benefit-cost analysis)	\$ 194.29	\$ (194.29)	\$ -
Transmission System Intelligence (benefit-cost analysis)	\$ 86.41	\$ (86.41)	\$ -
GIP Components Being Considered in Other Dockets	\$ 192.48	\$ (192.48)	\$ -
Energy Storage (NCUC #E-100, Sub 164)	\$ 129.00	\$ (129.00)	\$ -
Electric Transportation (NCUC #E-2 Sub 1197 & E-7 Sub 1195)	\$ 63.48	\$ (63.48)	\$ -
TOTALS	\$ 2,509.92	\$ (1,629.51)	\$ 880.41

2

3

Programs and sub-components that merit approval with conditions. Some

4

GIP programs merit approval with conditions. The mix of spending between and

5

even within the programs and sub-components would likely be optimized through

6

the use of a transparent, stakeholder-engaged distribution planning and capital

7

budgeting process. Programs that I believe merit approval with conditions,

8

amounting to \$374 million in capital, include (1) the Integrated Volt-VAR

1 Control (“IVVC”) program; (2) the flood and animal mitigation components of
2 the Transmission Hardening and Restoration program; (3) the Long Duration
3 Interruption/High Impact Sites program; (4) foundational software, including
4 Enterprise Applications, Integrated System Operations Planning (“ISOP”), and
5 Distributed Energy Resource (“DER”) dispatch; (5) Cybersecurity (excluding
6 substation physical security); and (6) Enterprise Communications (excluding
7 mission critical voice and data network investments pending further evaluation, as
8 described).

9 Self-Optimizing Grid. This program merits approval with conditions, but
10 at a reduced investment level (from \$722 million to \$385 million) so as to focus
11 the spending on the 50% of circuits and segments of highest priority/greatest
12 benefit. This will improve the benefit-to-cost ratio of self-optimizing grid
13 program capital and reduce the risk that the program is applied to circuits for
14 which costs exceed benefits. Reliability performance can be measured so that
15 informed consideration can be given to program expansion in the future. If the
16 Commission approves this program, I also recommend it keep a very close eye on
17 the \$48 million advanced distribution management system deployment.

18 Transmission Hardening and Resilience (not related to flood or animal
19 mitigation). My testimony explains why this capital budget (\$120 million) merits
20 approval with conditions but modifies the goal and design of the program
21 completely. As proposed, the program makes progress towards greater
22 accommodation of DER, but does not actually increase the capacity of Duke
23 Energy’s grid to accommodate more DER by a single watt. Instead, I recommend

1 this entire budget be focused on a smaller number of projects designed to increase
2 the capacity of Duke Energy's grid to accommodate more DER. These include
3 (1) upgrading 44kV lines to 100kV lines; and/or (2) increasing the number of
4 substations served by 44kV lines. The value of involving stakeholders in the
5 identification of 44kV lines and substations to maximize DER accommodation
6 benefit per dollar of capital is clear.

7 Programs to Reject Due to Lack of Cost-Effectiveness/Compliance with
8 Standard Practice. My testimony explains why these programs are not cost
9 effective and are not standard practice in the industry. Totalling \$660 million,
10 they include (1) targeted undergrounding; (2) distribution transformer retrofit; (3)
11 transformer bank replacement; (4) oil-filled breaker replacement; and (5) physical
12 substation security.

13 Programs to Reject Pending Further Evaluation. My testimony explains
14 that insufficient information is available to make a recommendation on these
15 programs. Witness Alvarez's testimony explains why a technical and economic
16 make vs. buy analysis, considering recent and emerging public telecom network
17 capabilities, is required before a recommendation regarding \$160 million in new
18 voice and data communications network investments can be determined. I also
19 note that no benefit-cost analysis has been completed on distribution automation
20 and transmission system intelligence programs and recommend that the
21 Commission reject them until Duke Energy completes these analyses.

22 **Q. PLEASE DESCRIBE THE CONDITIONS ON APPROVAL THAT YOU**
23 **RECOMMEND.**

1 A. I recommend the Commission apply three conditions for any GIP programs it
2 approves. The first condition is ongoing performance measurement against pre-
3 GIP baselines. I point specifically to measuring annual average voltage
4 reductions from the IVVC program, as well as SAIDI and SAIFI improvements
5 from the Self-Optimizing Grid program, but I believe a policy of performance
6 measurement is important for any extraordinary distribution investments the
7 Commission approves. There is no other way to determine if the program benefit
8 claims Duke Energy makes are reasonable, or if the approved programs should be
9 expanded or curtailed in the future.

10 The second of these conditions involve cost caps and associated operating
11 audits. As indicated in Witness Alvarez's testimony, Duke Energy never actually
12 provides a GIP capital budget limit or estimate of the cost to ratepayers. I
13 recommend the Commission establish capital cost caps for every GIP program or
14 sub-component it approves, as well as specifications for the program-specific
15 extents of capabilities it expects to be operational within the cost cap (generally,
16 as specified by Duke Energy in its GIP program descriptions and/or cost-benefit
17 analyses). Without cost caps or extent specifications (circuits, line miles,
18 substations, etc.), the Commission has no way of knowing whether promised
19 capabilities or extents are operating for the proposed costs. Program audits will
20 be needed to verify that capabilities have been implemented to the extent
21 promised for the costs estimated. The Commission may also wish to act on my
22 recommendation regarding financial consequences for exceeding program cost
23 caps or failing to deliver the promised extent of a program's capability within a

1 cost cap. As proposed, ratepayers bear all of these risks, and shareholders none of
2 these risks. Cost sharing between ratepayers and shareholders for cost overruns
3 or extent shortfalls would hold Duke Energy accountable for cost estimate
4 accuracy and program implementation success.

5 The third condition relates to capital Duke Energy spent on GIP assets
6 placed into service during the test year. For the GIP programs the Commission
7 approves, I recommend capital spent on GIP assets placed into service during the
8 test year be included in program cost caps as a condition of approval. For the GIP
9 programs the Commission rejects – and in particular, those programs it rejects due
10 to a lack of cost-effectiveness and industry standard practice compliance – I
11 recommend recovery of and on capital spent on such assets placed into service
12 during the test year be denied.

13 **Q. DO YOU HAVE OTHER RECOMMENDATIONS FOR THE**
14 **COMMISSION REGARDING THE GIP?**

15 A. Yes. My testimony indicates that many GIP programs are not cost-effective, and
16 outside standard industry practice, and that Duke Energy provides no economic
17 justification at all for other GIP programs. Witness Alvarez’s testimony indicates
18 that GIP program costs to ratepayers and communities are dramatically
19 understated and ratepayer benefits dramatically overstated. In this rate case Duke
20 Energy proposes deferral accounting treatment to address “regulatory lag” for GIP
21 costs. This serves to increase the likelihood that Duke Energy will earn or exceed
22 its authorized rate of return on equity, thereby increasing Duke Energy’s already-
23 adequate incentive to invest in its grid. I concur with Witness Alvarez’s

1 conclusion that deferral accounting treatment leads to excessive capital spending
2 on sub-optimal projects, and with his recommendation that deferral accounting for
3 GIP investments be rejected on that basis.

II. Historical Context

4 **Q. BEFORE PROCEEDING, PLEASE PROVIDE THE HISTORICAL**
5 **CONTEXT YOU MENTIONED.**

6 A. Since the introduction of alternating current and the power grid concept in the
7 early 20th century, utilities have taken a simple approach to grid planning. They
8 build systems to deliver power from an energy source to a consumer. As the
9 number, locations, and energy use of the consumers grew, utilities methodically
10 planned and implemented expansions in grids' geographic extents and energy
11 capacities over time. As grids developed, grid reliability and safety issues arose.
12 A solution was devised, which was the use of substations as hubs for protection
13 and control to deliver safe and reliable electricity to consumers via "spokes,"
14 which engineers know as circuits. Early grids were initially protected by fuses,
15 which later evolved into oil-filled circuit breakers in conjunction with analog
16 electromechanical relays, reclosers, and various devices to reduce circuits into
17 individualized sections. These protection systems were designed to de-energize
18 small sections of the grid, isolating faults and other problems to prevent damage
19 to the rest of the grid, and became the standard for grid protection and control.

20 **Q. HOW IS THIS HISTORICAL CONTEXT RELEVANT TO THIS**
21 **PROCEEDING?**

1 A. For over a century, utilities have successfully incorporated new technologies,
2 along with new operating practices, to deliver safe, reliable, and low-cost electric
3 distribution services under conditions of growing loads and increasing ratepayer
4 expectations. Utilities have done so using a methodical, common-sense approach
5 to distribution planning that focuses on a single question: do the benefits (i.e.,
6 reduction in risk of an adverse event such as a service interruption) justify the
7 costs? Over the course of many decades, a generally-accepted distribution
8 planning process, as well as a generally-accepted set of standard industry
9 practices, has arisen. Both the planning process and the standard practices are the
10 result of thousands of electrical engineers like me, asking this question thousands
11 of times while working on thousands of distribution circuits.

12 **Q. ARE YOU SUGGESTING THAT THERE IS NO NEED FOR**
13 **INNOVATION IN DISTRIBUTION PLANNING AND INVESTMENT?**

14 A. Not at all. While generally-accepted distribution planning processes and standard
15 practices have proven their value and should not be abandoned, this does not
16 mean they have not undergone, or should not undergo, adjustments from time to
17 time. Duke Energy Witness Oliver identifies megatrends prompting the
18 development of the GIP.⁵ I condense these down into two that require at least
19 some adaptation of utilities' historical distribution planning processes: (1) the
20 increasing penetration of distributed energy resources ("DER"), which can lead to
21 bi-directional power flow in high-enough capacities (towards the substation as
22 well as away from it); and (2) increased frequency of severe weather events.

⁵ *Direct Testimony of Jay W. Oliver, ("Oliver Direct"), Exhibit 2, p. 2 (September 30, 2019).*

1 However, I do not agree that these trends require a departure from best utility
2 practices in distribution planning. Changes in DER adoption and weather
3 severity simply require the application of new technology and practices on an as-
4 needed basis, justified through the technical reviews and cost-risk evaluations that
5 have always been a part of utility distribution planning processes. Stakeholders
6 can and should be part of these reviews, evaluations, and decisions. I also do not
7 agree that large investments in grid modernization require a change in the
8 methods by which utilities are compensated.

9 **Q. WHAT RELEVANCE DO YOUR CONTEXTUAL OBSERVATIONS HAVE**
10 **TO DUKE ENERGY’S GIP?**

11 A. Duke Energy’s GIP exhibits characteristics common to such plans issued by US
12 investor-owned utilities in recent years: (1) it was not developed according to best
13 practices in distribution planning; (2) it recommends investment dramatically
14 above and beyond “business as usual” investments; (3) it requests extraordinary
15 ratemaking treatment, which would provide additional incentive to invest; and (4)
16 it is justified by cost-benefit calculations based on irregularities and weak
17 assumptions, as described in Witness Alvarez’s testimony. I believe these
18 characteristics render the GIP fundamentally flawed, and that the GIP would not
19 meet North Carolina’s need for low-cost, safe, reliable, and increasingly clean
20 electricity.

21 The North Carolina economy and ratepayers can only bear so much rate
22 increase. As a result, grid investments must be very carefully considered and
23 prioritized. Failure to do so presents its own kinds of risks to the North Carolina

1 economy. It also presents risks to the achievement of North Carolina’s Clean
2 Energy Plan,⁶ as rate increases wasted on cost-ineffective investments are no
3 longer available to fund grid capabilities offering better “bang for the buck.” My
4 testimony is intended to provide a basic technical evaluation of GIP programs and
5 sub-components to help the Commission make informed choices regarding Duke
6 Energy’s GIP.

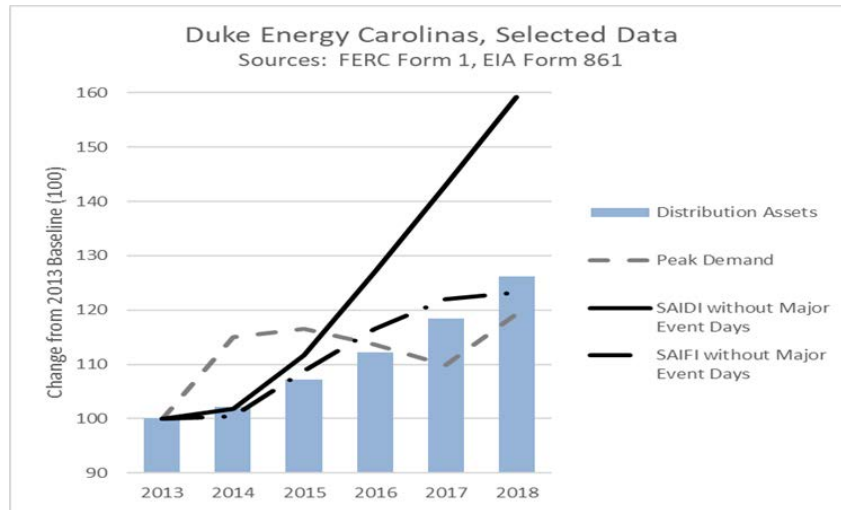
7 **Q. PLEASE PROVIDE EVIDENCE TO SUPPORT YOUR ASSERTION THAT**
8 **RELIABILITY OF DUKE ENERGY’S NORTH CAROLINA GRID HAS**
9 **DETERIORATED SIGNIFICANTLY IN RECENT YEARS DESPITE**
10 **DRAMATIC INCREASES IN GRID INVESTMENT.**

11 A. I completed the same reliability vs. investment analyses for DEC (Figure 1) and
12 DEP (Figure 2) that Witness Alvarez completed on a national basis, which is
13 contained in his testimony that is being filed in this docket concurrently.⁷ While
14 growth in peak demand does justify much of DEC’s and DEP’s grid investment
15 increases, DEC and DEP’s respective grid investment increases exceed peak
16 demand growth by 37% and 61%⁸. One would hope these excess investments
17 would lead to at least some reliability improvements. Yet, as is the case
18 nationally, DEC and DEP’s performance under key indices of reliability, SAIDI
19 and SAIFI, have deteriorated significantly despite grid investment in excess of
20 capacity needs. (Note that for SAIDI and SAIFI, lower values represent better
21 performance.)

⁶ Report by the North Carolina Department of Environmental Quality. October, 2019. Available here:
https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf

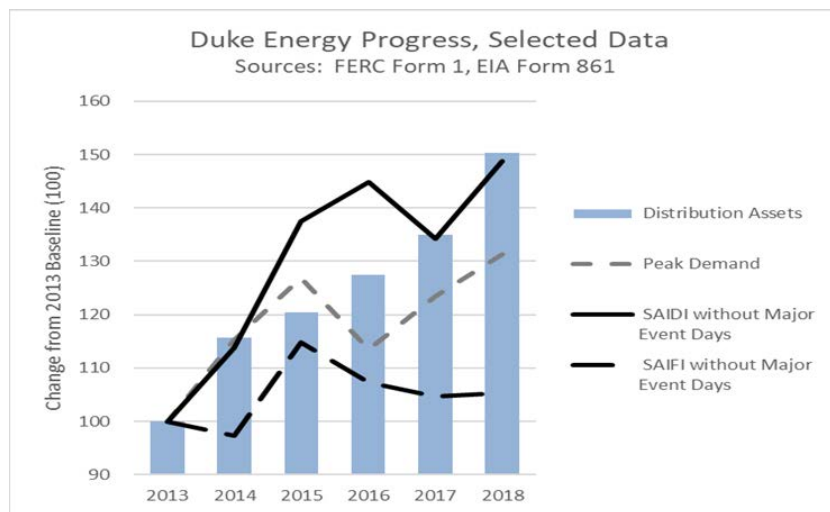
⁷ Sources: FERC Form 1 and EIA Form 861 data, 2013 through 2018.

1 *Figure 1: Relationship between Grid Investment and Reliability for DEC*



2

3 *Figure 2: Relationship between Grid Investment and Reliability for DEP⁹*



4

5 As shown in Figure 1, DEC’s SAIDI and SAIFI performance have
6 deteriorated almost 60% and more than 20%, respectively, since 2013 despite grid
7 investment growth 37% greater than peak demand growth. As shown in Figure 2,
8 DEP’s SAIDI and SAIFI performance have deteriorated almost 50% and more

⁹ As referenced above, DEC and DEP are each presenting the GIP program for approval in their respective concurrent rate cases. To that end, I have included DEC and DEP analysis here as it supports my point that historical investments do not correlate with SAIDI and SAIFI improvements. I believe this is a key indictment of the GIP.

1 than 5%, respectively, since 2013 despite grid investment growth 61% greater
2 than peak demand growth.

3 **Q. WHAT DO YOU CONCLUDE FROM THIS DATA?**

4 A. I do not conclude from this data that investments in reliability or weather event
5 resilience are bad ideas. Instead, I conclude from this data that the grid
6 investments that DEC and DEP been making in recent years do not appear to be
7 achieving the intended results. In light of this, Duke's proposed investments in the
8 grid to improve reliability, enhance resilience, or facilitate deployment of DERs
9 must be very carefully considered and prioritized.

III. GIP Programs Meriting Approval with Conditions

10 **Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR**
11 **TESTIMONY.**

12 A. Should the Commission disagree with my primary recommendation to deny the
13 request for approval of the GIP and institute a proceeding to develop a
14 transparent, stakeholder-engaged distribution planning and capital budgeting
15 process, then, in the alternative, some of the GIP programs may be approved with
16 conditions. In this section of my testimony, I will discuss the GIP programs and
17 sub-components that I believe, under my secondary recommendation, may merit
18 approval with conditions. I will describe my rationale for these programs' merits,
19 as well as conditions I believe the Commission should require in the event it
20 approves spending for these programs and sub-components. I will conclude this
21 section with a discussion regarding the potential value of a transparent,
22 stakeholder-engaged distribution planning and capital budgeting process, as I

1 believe such a process could improve the GIP even among meritorious programs.
2 The GIP programs and sub-programs that I believe may merit approval with
3 conditions include:

- 4 • Integrated Volt-VAR Control (“IVVC”);
- 5 • Flood and Animal Mitigation portions of Transmission Hardening and
6 Resilience;
- 7 • Long Duration Interruption/High Impact Sites;
- 8 • Enterprise Applications, ISOP software, and DER dispatch software;
- 9 • Cyber security portions of Physical and Cyber Security; and
- 10 • Power electronics for Volt-VAR Control.

11 **Q. WHY DO YOU BELIEVE THESE GIP PROGRAMS MAY MERIT**
12 **APPROVAL WITH CONDITIONS?**

13 A. All of the GIP programs on this list satisfy one or more of the following criteria:

- 14 • They represent standard industry practice;
- 15 • They consist of software needed to optimize grid assets or operations, or
16 to improve cyber security;
- 17 • They are likely, with conditions, to deliver benefits to ratepayers in excess
18 of costs to ratepayers without material modifications of the program as
19 proposed;
- 20 • They are critical to stakeholders' value that cannot be otherwise secured.

21 **Q. WHAT CONDITIONS DO YOU RECOMMEND THE COMMISSION**
22 **ATTACH TO APPROVAL OF THESE PROGRAMS?**

1 A. The Commission should consider attaching a common set of conditions to any
2 and every GIP program it might approve. These conditions include cost controls,
3 operating audits, and performance measurement.

4 **Q. PLEASE DESCRIBE THE COST CONTROL CONDITIONS.**

5 A. As described in Witness Alvarez’s testimony, there are significant differences
6 between the program capital amounts provided in the GIP¹⁰ and the program
7 capital amounts provided in the benefit-cost analyses. I also note the equivocal
8 response to a clear request during discovery about the amount of capital being
9 requested for the GIP, to which Duke Energy responded it is only requesting,
10 though I am paraphrasing: (1) a return on and of capital spent on GIP assets
11 placed in service as of the closing date of this rate case; and (2) deferred
12 accounting treatment for GIP assets placed in service between this rate case and
13 the next rate case.¹¹ I find this level of ambiguity concerning, and believe the
14 Commission should share my concern. I do not believe ratepayers will be best
15 served if Duke Energy treats GIP capital as a pot of money it can invest as it
16 wishes.

17 Instead, any GIP program the Commission approves should include a
18 clearly defined functional scope, a clearly defined geographic scope, and capital
19 budget sufficient to secure the functionality for the defined geography. This is
20 consistent with the accountability issue Witness Alvarez raises in his testimony,
21 but on the cost side of the benefit-cost equation. Furthermore, I am concerned

¹⁰ Oliver Direct, Exhibit 10, page 3.

¹¹ DEC response to NCJC et al. Data Request No. (hereinafter, “DR”) 5-4(a), attached as Stephens Exhibit 2.

1 that ratepayers will bear 100% of the risk of any cost overruns or scope
2 shortcomings. I encourage the Commission to consider cost caps for specific
3 programs and scopes, complete with ratepayer protections (such as 50/50 cost
4 sharing between ratepayers and shareholders for cost overruns). Finally, program
5 cost caps should incorporate all capital for each program, including capital spent
6 prior to the end of the test year in this rate case.

7 **Q. PLEASE DESCRIBE THE OPERATING AUDITS.**

8 A. This condition is closely tied to cost caps. In my experience, an investor-owned
9 utility at risk for exceeding a cost cap with consequences will simply reduce
10 functionality or geographic scope in order to remain under the cap/avoid the
11 consequences. This is not the intended outcome of the cost caps condition. As a
12 result, I also recommend operating audits, with appropriate use of random
13 sampling, to validate the functionality and geographic scope of any and all
14 approved GIP programs. For example, if the GIP proposes that Duke Energy will
15 add IVVC to 1800 circuits for \$200 million by 2024, an operating audit conducted
16 in 2025 should validate that IVVC software is providing instructions to IVVC
17 equipment installed on 1800 circuits.

18 **Q. PLEASE DESCRIBE PERFORMANCE MEASUREMENT CONDITIONS.**

19 A. Performance measurement should be a condition of every program for which
20 performance is likely to be variable. Baseline performance levels should be
21 measured before capabilities are added, and post-deployment performance should
22 be measured on an ongoing basis. Performance measurement is critical for

1 ensuring that ratepayer benefits are being maximized, and increased over time,
2 but also to inform potential future expansions or curtailments of GIP programs.

3 In this group of meritorious programs, IVVC stands out as a program
4 requiring performance measurement. Duke Energy should be required to report
5 baseline and annual average voltage for every circuit with IVVC capabilities.
6 Ameren Illinois' IVVC measurement and validation program is an excellent
7 example of sound IVVC performance measurement.¹²

8 **Q. BEFORE PROCEEDING, PLEASE COMMENT ON THE**
9 **RESTRICTIONS THAT DUKE ENERGY IS PLACING ON DER**
10 **INSTALLATIONS DUE TO VOLTAGE CONCERNS.**

11 A. In its Method of Service Guidelines, Duke Energy describes limitations it is
12 placing on DER locations due to operational voltage issues. The rationale for
13 these limitations -- challenges associated with non-standard line voltage regulator
14 ("LVR") settings -- are not valid from a technical perspective. I can understand
15 why grid operators would want to minimize the reconfiguration flexibility
16 reductions associated with non-standard LVR settings. But new loads routinely
17 serve to reduce reconfiguration flexibility; it is part of grid operators' job to
18 manage around reconfiguration flexibility reductions, and they do so successfully
19 all the time. Regarding backfeed, it is easy to manage as long as DER relative to
20 load is not extremely high. When DER relative to load does get high,
21 technologies are available to manage backfeed. Nor are voltage issues generally,
22 or the presence of IVVC capabilities specifically, a reason to restrict DER on a

¹² Illinois Commerce Commission 18-0211. *Ameren Illinois Voltage Optimization Plan*. Jan 25, 2018. P. 27-30.

1 circuit. Capacitor banks, smart inverters, and IVVC software setting adjustments
2 can all be employed to cope with volt-VAR issues related to DER.

3 To summarize, neither stakeholders nor the Commission should accept
4 Duke Energy's limitations on DER without a technical challenge. The fact that a
5 DER installation might make a grid operator's job more difficult is not an
6 acceptable restriction rationale, and the software Duke Energy is installing, and
7 which I have categorized as "merits approval with conditions" in this testimony,
8 will help grid operators manage DER capacity growth. The unwarranted
9 restriction of DER locations appears to me to be yet another reason to implement
10 a transparent, stakeholder-engaged distribution planning and capital budgeting
11 process in North Carolina.

12 **Q. WHAT KIND OF VALUE COULD A TRANSPARENT, STAKEHOLDER-**
13 **ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING**
14 **PROCESS DELIVER REGARDING THE MERITORIOUS PROGRAMS**
15 **YOU DESCRIBE IN THIS SECTION?**

16 A. Witness Alvarez's testimony describes a transparent, stakeholder-engaged
17 distribution planning and capital budgeting process that warrants Commission
18 consideration. While some will perceive such a process as an attempt to limit grid
19 investment, I prefer to think of it as a way to optimize grid investment. For
20 example, while I believe the GIP programs listed in this section may merit
21 approval, I pass no judgement regarding the relative size or mix of the
22 investments. Should the GIP devote more capital to the IVVC program and less
23 on cybersecurity? Maybe; it depends on priorities, perceptions of threats, degree
24 of program effectiveness, risk tolerance, and a host of other variables that exist to

1 varying degrees within various ratepayers and stakeholders. When a utility makes
2 these decisions for us, it can only fight stakeholders, as any decision the utility
3 makes will put it on the wrong side of some stakeholders' interests. When a
4 utility works with stakeholders as a trusted advisor, explaining the pros and cons
5 of various approaches to an emerging issue or opportunity, it is able to better align
6 goals, interests, and priorities and make the right investment choices.

IV. GIP Programs Requiring Material Modifications and Conditions to Merit Approval

7 **Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR**
8 **TESTIMONY.**

9 A. In this section of my testimony, I will discuss the GIP programs that must be
10 materially modified in order to merit Commission approval under my secondary
11 recommendation, including the Self-Optimizing Grid (“SOG”) and Transmission
12 Hardening and Resilience Programs. I will recommend that the SOG budget,
13 should the Commission approve the program, be reduced to better focus capital
14 on high-priority circuits and sections. I will recommend that the Transmission
15 Hardening and Resilience programs be dedicated solely to actual capacity
16 increases designed to accommodate more DER before they can merit approval.
17 Otherwise, I recommend the Commission reject this spending entirely. I will also
18 identify opportunities for a transparent, stakeholder-engaged distribution planning
19 and capital budgeting process to deliver value when considering capital outlays
20 for these types of programs.

1 A. *Self-Optimizing Grid*

2 **Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR**
3 **DUKE ENERGY'S SOG PROGRAM?**

4 A. The notion of “networking” circuits or substations so that a source of back-up
5 power is available in the event the primary source fails is nothing new. Utilities,
6 including DEC and DEP, have been sectionalizing circuits and building back-up
7 supply lines (called tie lines) for decades. Duke Energy’s SOG program simply
8 does more of this networking, allows it to be executed remotely (without sending
9 linemen in trucks to throw switches), and with less preparatory analysis (through
10 software) to ensure a grid reconfiguration doesn’t create more problems than it
11 solves. However, like all investments intended to improve reliability, the law of
12 diminishing returns applies. That is, every incremental capital dollar spent
13 delivers less incremental reliability improvement than the capital dollar just spent.
14 As mentioned by Witness Alvarez in his testimony, there is a balance to be struck
15 between reliability and affordability. Taken to an extreme, our grid could be made
16 perfectly reliable, though few would be able to afford electricity. As it relates to
17 the SOG program, the questions are (1) to what extent/which circuits to apply it;
18 and (2) into how many sections should each circuit be split?

19 **Q. HOW DOES ONE DETERMINE THE NUMBER OF/SELECT CIRCUITS**
20 **TO WHICH TO APPLY THE NETWORKING CONCEPT?**

21 A. It is part art and part science, and is yet another example of why a transparent,
22 stakeholder-engaged approach to distribution planning and capital budgeting
23 creates value for ratepayers. All else being equal, circuits with greater numbers of
24 ratepayers will receive greater benefits from networking than circuits with fewer

1 numbers of ratepayers. But not all ratepayers are created equal. As the long
2 duration interruption/high impact sites program recognizes, reliability is more
3 critical to some facilities/districts (hospitals, airports, downtowns) than others.
4 What I can tell you for certain is that the benefit-to-cost ratio improves as the
5 focus of networking spending tightens. The concept is best illustrated by
6 example. Consider six circuits, each of which has the same cost for networking,
7 and a variety of projected benefits:

Circuit Number	Networking Cost	Projected Benefit
1	\$2	\$3.00
2	\$2	\$2.75
3	\$2	\$2.50
4	\$2	\$2.25
5	\$2	\$2.10
6	\$2	\$2.05
Totals	\$12	\$14.65

8
9 Assume that cost estimates are solid, but that benefit estimates are less so. As
10 Witness Alvarez's testimony indicates, benefit estimates are generally subject to a
11 significant number of assumptions that cannot be assured. While the networking
12 program in the hypothetical example indicates a benefit-to-cost ratio of 1.2 to 1
13 (\$14.65/\$12), the benefit cost ratio could be improved to 1.65 to 1 (\$8.25/\$5) by
14 limiting the investment to the first three circuits. Note that a benefit variance of
15 as little as 10% makes circuits 5 and 6 cost-ineffective, and a benefit variance of

1 as little as 15% also makes circuit 4 cost-ineffective. So, reducing the number of
2 circuits not only improves the benefit-to-cost ratio, it reduces the risk that the
3 treatment (in this case SOG) will cost more than the benefits delivered,
4 particularly considering the variability surrounding benefit estimates.

5 **Q. HOW DOES ONE DETERMINE THE NUMBER OF SEGMENTS INTO**
6 **WHICH A CIRCUIT SHOULD BE DIVIDED?**

7 A. The law of diminishing returns applies here too. Consider a circuit with 1,000
8 ratepayers. Splitting this circuit up into two segments will enable 500 ratepayers
9 to receive power from a back-up source when the primary source fails, a 50%
10 improvement. Now consider splitting this circuit into three circuits, which would
11 enable 667 ratepayers to receive power from a back-up source when the primary
12 source fails. While a 66% improvement is better than a 50% improvement, note
13 that the incremental improvement of three sections over two is only 16%, while
14 the incremental improvement of two sections over one is 50%. Each additional
15 section – four, five, or six – will each deliver less and less incremental benefit.
16 Such is the law of diminishing returns, and the concept is useful to consider not
17 just within a program, but between programs, and even for an overall distribution
18 rate base. It is yet another example of why distribution planning and capital
19 budgets must be carefully considered and prioritized, ideally with the input of
20 educated and informed stakeholders.

21 **Q. HOW DO THESE OBSERVATIONS INFORM YOUR**
22 **RECOMMENDATION FOR MATERIAL MODIFICATIONS TO DUKE**
23 **ENERGY'S SOG PROGRAM?**

1 A. My recommendation is that the fixed costs of the SOG proposal, including the
2 Advanced Distribution Management System (“ADMS”) and proof-of-concept
3 (\$48.9 million) be approved, while the variable portion – the extent to which SOG
4 is deployed geographically – be cut in half (from \$673.6 million to \$336.8
5 million). While I have significant concerns about ADMS, which I will discuss, I
6 believe this solution will increase the benefit-to-cost ratio of the SOG program,
7 and reduce the risk that SOG capital will be applied to circuits that will not
8 deliver benefits in excess of cost. As indicated in Witness Alvarez’s testimony,
9 the reliability of Duke Energy’s benefit estimates is questionable, meaning that
10 variability in benefit delivery is likely to be high. Stakeholder engagement could
11 be used to establish criteria for circuit prioritization.

12 Another reason to cut the SOG capital budget is the high degree of
13 variation in capital cost estimates. In discovery, Duke Energy admitted that SOG
14 cost estimates were prepared at an AACE Class 4 level of detail.¹³ Class 4 cost
15 estimates are only accurate to within minus 30%/plus50%, so better to approve a
16 smaller budget until better cost estimates can be developed for specific circuits.
17 Finally, all the conditions I described in the previous section of my testimony –
18 cost caps, operating audits, and performance measurement – should apply to all
19 programs, including SOG, which the Commission elects to approve (if any).

20 **Q. WHAT ARE YOUR CONCERNS ABOUT DUKE ENERGY’S \$48**
21 **MILLION ADMS PROPOSAL?**

¹³ DEC response to NCJC DR 4-06, attached as Stephens Exhibit 3.

1 A. ADMS consists of a suite of software applications that are then combined into a
2 single operating platform. In my experience, the value comes from the underlying
3 software applications, including fault locating, isolation and service restoration
4 (“FLISR”) and integrated Volt-VAR control (“IVVC”). In general, with the
5 possible exception of outage management system integration, the combination
6 into a single operating platform, though intuitively appealing, provides little
7 actual economic benefit. Similarly, I have seen utilities waste tens of millions of
8 dollars pursuing grid automation – enabling software, not grid operators in control
9 centers – to reconfigure the grid. Not only is this sort of automation extremely
10 costly to implement, to little economic benefit, it requires an extreme, ongoing
11 level of dedication and attention to field device software updates, GIS map system
12 accuracy, accurate location and device setting monitoring, communications
13 network attention, and logical equipment identification. If the logical
14 specifications do not precisely match physical specifications, for every device,
15 100% of the time, automation efforts will fail.¹⁴ When O&M budgets are
16 stretched, or under the pressure of a service restoration effort, humans take
17 shortcuts. Full grid automation, where some see ADMS heading, thus requires a
18 level of management and employee attention that may be unattainable, and
19 involves a great deal of risk. Due to the underlying suite of software applications,
20 I hesitate to recommend the Commission reject ADMS. But, due to the

¹⁴ Many of these concerns are described in a US Department of Energy whitepaper dedicated to the subject. US Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems*. Whitepaper. February, 2015, <https://www.energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf>.

1 challenges and overreaches I describe, I absolutely recommend the Commission
2 apply cost cap and operating audit conditions to any self-optimizing grid and
3 ADMS capital spending the Commission might approve.

4 *B. Transmission Hardening and Resilience (Excluding Flood and Animal*
5 *Mitigation)*

6 **Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR**
7 **DUKE ENERGY'S TRANSMISSION HARDENING AND RESILIENCE**
8 **PROGRAM?**

9 A. While my suggested modifications to the self-optimizing grid program amounted
10 to a relatively simple reduction in scope, my suggested modifications to the
11 transmission hardening and resilience program amount to a complete redesign of
12 the program and a repurposing of the \$120 million transmission hardening and
13 resilience budget (excluding substation flood and animal mitigation components,
14 which I included in the “merit approval” category).

15 **Q. WHY DO YOU RECOMMEND THE TRANSMISSION HARDENING AND**
16 **RESILIENCE BUDGET BE COMPLETELY REPURPOSED?**

17 A. Duke Energy describes its transmission hardening and resilience program as a
18 way to improve reliability, projecting that ratepayers will receive \$2 billion in
19 economic benefits. However, given the extremely low historical failure rates of
20 the 44kV equipment DEC proposes to replace, including conductors, static lines,
21 and support structures, there is no way the replacements proposed can possibly
22 avoid the number of failures required to produce the economic benefits

1 projected.¹⁵ In my experience, low transmission failure rates are common, as
2 transmission designers recognize the larger number of ratepayers impacted by
3 failures on such systems, and overbuild accordingly. But my concerns regarding
4 benefit projects are trumped by an even bigger concern: the transmission
5 hardening and restoration program proposed will not increase the capacity of the
6 44kV system to accommodate greater DER capacity by a single watt.

7 **Q. ARE YOU SURE? DUKE ENERGY'S GIP STATES ITS TRANSMISSION**
8 **AND RESILIENCE PROGRAM "BEGINS TO PAVE THE WAY FOR**
9 **MORE DER INTERCONNECTIONS."**

10 A. In replacing 44kV lines, Duke Energy is replacing the support structures (poles)
11 with stronger structures (towers) designed to hold the heavier weight of 100kV
12 conductor. However, Duke Energy is not replacing any of the other 44kV
13 equipment on these lines – switches, voltage regulators, circuit breakers, etc. –
14 with 100kV equipment. Without such equipment, Duke Energy will be unable to
15 operate the new lines at 100kV. This does not represent standard industry
16 practice. In Phase 1, Duke Energy is investing as much capital as it can justify
17 while accommodating as little new DER as possible (in this case, zero). In Phase
18 2, with no defined timeframe, Duke Energy would actually install the equipment
19 required to operate the lines at 100kV; in Phase 3, with no defined timeframe,
20 Duke Energy will expand the 44kV network to more substations. Phases 2 and 3
21 will increase the DER capacity Duke Energy's grid can accommodate; Phase 1
22 will not. Nor, as described above and by Witness Alvarez, will Phase 1 deliver

¹⁵ Witness Alvarez provides these historical failure rates in his testimony.

1 the reliability benefits Duke Energy projects. My recommendation is to repurpose
2 the \$120 million Duke Energy proposes to invest in Phase 1 in a smaller number
3 of projects incorporating Phases 2 and 3. Stakeholder engagement would be
4 valuable in allocating this capital in ways that maximize the amount of new DER
5 capacity accommodated for the least cost. The deficiencies in Duke Energy's
6 44kV upgrade proposal illustrate the potential value of a transparent, stakeholder-
7 engaged distribution planning and capital budgeting process.

**V. GIP Programs That Should Be Rejected Due to Lack of Cost
Effectiveness/Compliance with Standard Industry Practice**

8 **Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR**
9 **TESTIMONY.**

10 A. In this section of my testimony, I will discuss GIP programs that should be
11 rejected in any scenario. None of these programs are standard industry practice as
12 they are generally recognized as not cost-effective. They include:

- 13 • Targeted Undergrounding (\$114.5 million);
- 14 • Distribution Transformer Retrofits (\$118.0 million);
- 15 • Transformer Bank Replacements (\$116.4 million);
- 16 • Oil-Filled Breaker Replacements (\$200.3 million); and
- 17 • Substation Physical Security (\$110.7 million).

18 A. *Targeting Undergrounding*

19 **Q. WHY DO YOU BELIEVE TARGETED UNDERGROUNDING MERITS**
20 **REJECTION?**

1 A. Undergrounding of overhead lines is not a standard industry practice for many
2 reasons. Undergrounding may be intuitively appealing, but it is not the panacea
3 that utilities would like stakeholders to believe. While undergrounding reduces
4 the risk of service interruptions due to vegetation contact and weather, it increases
5 the risk of service interruptions due to flooding and digging. While
6 undergrounding reduces the hassle associated with repairing lines in residential
7 ratepayers' backyards, the time to locate and repair underground faults generally
8 takes longer than the time to locate and repair faults on overhead lines. While
9 aesthetically appealing in principle, in practice almost 100% of utility poles will
10 remain in place, supporting telephone, Internet, and cable television service lines.
11 While undergrounding may eliminate a small portion of Duke Energy's tree
12 trimming costs, some other service provider will still need to clear vegetation, that
13 means ratepayers will still pay; underground cable is also more costly than
14 overhead conductor, and must be replaced more frequently. A Lawrence Berkeley
15 National Laboratory review of undergrounding programs also noted an increase in
16 utility employee safety risks associated with undergrounding.¹⁶

17 Furthermore, undergrounding is extremely costly and not cost-effective,
18 and it is not simply my experience that tells me so. The Lawrence Berkeley
19 National Lab undergrounding study indicates that the benefit-to-cost ratio of
20 undergrounding is 0.3 to 1.0 (that is, costs exceed benefits by a factor of more

¹⁶ Larsen P. A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines. Lawrence Berkeley National Laboratory. October 2016. Page 7.¹⁷ Ibid, parts of the document not paginated, see PDF file page 42.

1 than three).¹⁷ For these reasons, the Virginia State Corporation Commission
2 (“SCC”) rejected undergrounding programs proposed by Dominion multiple
3 times. Duke Energy’s program proposes to underground the lines serving just
4 22,477 ratepayers¹⁸ at a cost of \$169.3 million,¹⁹ or at least \$7,500 per ratepayer
5 undergrounded. To justify the program, Duke Energy claims that undergrounding
6 will reduce the momentary outages to commercial and industrial (“C&I”)
7 ratepayers upstream of the residential areas. In fact, Duke Energy attributes of
8 90% of the benefits it projects from targeted undergrounding to this single value
9 proposition.

10 **Q. DO YOU BELIEVE THAT JUSTIFYING THE INSTALLATION OF**
11 **TARGETED UNDERGROUNDING BASED ON THE EFFECT OF**
12 **UPSTREAM MOMENTARY OUTAGES IS INAPPROPRIATE?**

13 A. As indicated in Mr. Alvarez’s testimony, the cost per momentary outage to various
14 rate class ratepayers is exaggerated. In addition, I would like to point out a few
15 factors that contribute to Duke Energy’s exaggeration of the amount of upstream
16 momentaries caused by backlot line overhead lines.

17 First, Duke Energy admitted in discovery that not all outages result in an
18 upstream momentary event.²⁰ The purpose of coordinating the operation of fuses
19 with upstream devices is often intended to eliminate an upstream operation. That
20 is to say, that the upstream relay is set such that the downstream fuse will clear or

¹⁷ Ibid, parts of the document not paginated, see PDF file page 42.

¹⁸ Oliver Direct, Ex. 7 workbook “TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx”, tab “Area Data – Condensed”, line “Total Ratepayers Affected”.

¹⁹ Ibid, tab “All Years Tab Summary”, cell D21.

²⁰ DEC response to NCSEA DR 3-32, attached as Stephens Exhibit 4.

1 blow, for faults of sufficient magnitude, resulting in no upstream momentary
2 outage.

3 Second, the reason for most momentary outages is that the utility has
4 installed a “Fast” or “Fuse Saving” relay setting on the upstream device, which is
5 designed to open the upstream device and allow a fault to clear. This opening
6 operation is the momentary outage. These upstream device settings are typically
7 set for one fast trip before moving to the slower trips which would cause a
8 downstream device such as a fuse to clear. The point is, a simple adjustment to
9 upstream device trip settings can eliminate C&I momentaries caused by
10 downstream events.

11 Third, Duke Energy’s reliability improvement estimates assume 2.7
12 momentaries for every sustained outage. I believe this estimate is too high. As
13 indicated above, relays are typically set for one fast trip, not multiple fast trips,
14 which would result in one momentary upstream outage before the fuse clears, not
15 2.7. The fuse again would be coordinated with the relay setting following the
16 “Fast” trip setting such that the fuse would clear prior to the upstream device
17 opening again after the fast trip opening. This would result in one momentary for
18 upstream ratepayers. The only reasonable course of action is to evaluate the
19 upstream momentaries on a circuit-by-circuit basis.

20 Fourth, Duke Energy admitted in discovery that eliminating the “Fast”
21 Trip on the upstream device would eliminate most of the momentaries

1 experienced by the upstream C&I ratepayers.²¹ Duke Energy did point out that
2 this would result in increased downstream outages and trips to the field; however,
3 the value Duke Energy placed on upstream C&I ratepayer momentaries greatly
4 outweighs the value of downstream outages. If this is the case, then the best
5 course of action would be to eliminate the “Fast” trip setting on upstream devices
6 rather than spend \$114.5 million undergrounding downstream segments in just 55
7 neighborhoods.

8 Finally, I note that estimated economic benefits for many GIP programs
9 consist largely or mainly of a reduction in upstream momentaries for C&I
10 ratepayers. The preceding comments apply to all of these programs.

11 *B. Distribution Transformer Retrofits*

12 **Q. WHY DO YOU BELIEVE THE DISTRIBUTION TRANSFORMER**
13 **RETROFIT PROGRAM MERITS REJECTION?**

14 *A.* The distribution transformer retrofit program that Duke Energy is proposing is not
15 standard practice, and is not likely cost-effective. Duke Energy operates 784,000
16 distribution transformers in North Carolina; in an average year slightly fewer than
17 6,000 of them, or less than 1%, will fail.²² As with targeted undergrounding, the
18 value proposition proffered by Duke consists almost entirely of protecting C&I
19 ratepayers from downstream service outages; 93% of the benefits Duke Energy
20 projects stem from this claim.²³ Duke indicates that the transformers and

²¹ DEC response to NCJC DR 5-33, attached as Stephens Exhibit 5.

²² Oliver Direct, Ex. 7 workbook “HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx”, tab “Selection Metric – Tx Retrofit NC”, cell C31 plus cell C34 (incidents) divided by cell 65 (total transformer count).

²³ Ibid. Tab “NPV-Tx Retrofit NC”.

1 secondary systems that are planned for retrofit are operating safely.²⁴
2 Additionally, Duke could provide no indication of outages or outage complaints
3 associated with these transformers on secondary lines²⁵

4 Duke indicated that many of the transformers that are involved in the
5 retrofit project are Completely Self Protected (“CSP”) transformers.²⁶ These
6 transformers have internal fuses that protect the transformer from internal faults.
7 Thus, even though the distribution transformer retrofit project is intended to
8 protect the transformer and the secondary line, the program is duplicative for the
9 transformer portion of the value proposition.

10 In discovery, Duke Energy indicated the trip setting on the transformer
11 retrofit devices would be set such that the retrofitted distribution transformer
12 would trip before any upstream devices could trip.²⁷ This is counterproductive.
13 The reason for enabling a fast trip setting on upstream devices is to allow a fault
14 to clear before the downstream device (in this case the retrofitted distribution
15 transformer) clears or opens. The transformer retrofit program would install a
16 device downstream that clears or opens before the upstream fast trip device can
17 prevent it from operating. This is clearly counterproductive and a waste.

18 C. *Transformer Bank Replacement*

19 **Q. EXPLAIN WHY THE TRANSFORMER BANK REPLACEMENT**
20 **PROGRAM SHOULD BE REJECTED.**

²⁴ DEC response to NCJC DR 8-34, attached as Stephens Exhibit 6.

²⁵ *Id.*

²⁶ Stephens Exhibit 6. DEC could not provide an exact count; however, most of the distribution transformers installed by utilities in the last 40 years have been of the CSP type.

²⁷ DEC response to NCJC DR 5-40, attached as Stephens Exhibit 7.

1 A. Substation transformers are typically situated in groups of three, constituting a
2 transformer bank. Unlike distribution transformers, substation transformers (also
3 known as transmission transformers) typically serve one or two thousand
4 ratepayers each. However, as transformer oil can be tested, and used to predict
5 transformer failure, there is no reason whatsoever to replace transformers in the
6 absence of test results. As a result, substation transformer oil testing and failure
7 prediction is a standard industry practice; prospective substation transformer
8 replacement in the absence of test results is not.

9 Witness Alvarez provides historical substation transformer failure rates in
10 his testimony; they are extremely low, as I would expect. The large benefits Duke
11 Energy projects from avoiding future transformer failures through prospective
12 replacement do not square at all with historically low transformer failure rates.
13 Prospective substation transformer replacement, and particularly the proactive
14 replacement of entire transformer banks, in the absence of test results, should be
15 rejected.

16 D. *Oil-Filled Breaker Replacement*

17 Q. **EXPLAIN WHY THE OIL-FILLED BREAKER REPLACEMENT**
18 **PROGRAM SHOULD BE REJECTED.**

19 A. Circuit breakers, like transformers, can be tested. It is standard industry practice
20 to test circuit breakers at regular intervals, and to track the number of operations
21 (trips) for each breaker. When a circuit breaker fails a test, or reaches its rated
22 number of operations, it is standard industry practice to replace it. Replacing

1 circuit breakers in the absence of test failure or operating counts is not standard
2 practice.

3 Again, there is a reason prospective circuit breaker replacement is not
4 standard industry practice. Witness Alvarez provides historical circuit breaker
5 failure rates in his testimony; as with transformer failures, the failure rate has been
6 extremely low. The large benefits Duke Energy projects from avoiding future
7 circuit breaker failures through prospective replacement do not reconcile with
8 historically low transformer failure rates.

9 **Q. BUT DUKE ENERGY DESCRIBES BENEFITS OTHER THAN**
10 **RELIABILITY IMPROVEMENTS FROM CIRCUIT BREAKER**
11 **REPLACEMENT, DOES IT NOT?**

12 A. Yes. Duke Energy claims that the new circuit breakers will have remote
13 monitoring and control capabilities that the oil circuit breakers do not have.
14 While this may be true, I note that retrofit kits are available to provide these same
15 capabilities for oil circuit breakers at the fraction of the cost of a new circuit
16 breaker. Duke Energy also claims that about one-third of the economic benefits
17 of the circuit breaker replacement program stem from the avoidance of
18 replacement in the future. I do not see this as a “benefit” at all. When a circuit
19 breaker needs to be replaced, it should be replaced. Replacing a circuit breaker
20 before it becomes necessary to do so does not avoid any costs at all; rather, it
21 advances the cost, requiring ratepayers to pay today for something they could
22 have been spared until some future test failure. I note Duke Energy applies this
23 nonsensical benefit to other programs too, including targeted undergrounding and

1 transformer bank replacement. Witness Alvarez quantifies this in his testimony
2 regarding overstated benefits.

3 *E. Substation Physical Security*

4 **Q. EXPLAIN WHY THE PHYSICAL SUBSTATION SECURITY PROGRAM**
5 **SHOULD BE REJECTED.**

6 A. As with the other programs that merit rejection, there is no standard industry
7 practice or security standard associated with the physical substation security
8 upgrades Duke Energy is proposing. The physical substation security program
9 includes the installation of high-security fencing, gates, cameras, and lighting at a
10 cost of \$4.2 million per substation. This amount includes \$800,000 per substation
11 just for a prefabricated building to house physical security equipment.²⁸ At a
12 proposed budget of \$110 million, this program will upgrade the physical security
13 of just 27 substations. Although that will leave Duke Energy with 2,088 (99%) of
14 its substations with standard fencing, I am pleased to report that Duke Energy has
15 never recorded a single incident of unauthorized substation intrusion.²⁹ There
16 must be more valuable ways for Duke Energy to deploy capital, and this proposed
17 program illustrates another potential opportunity for a transparent, stakeholder-
18 engaged distribution planning and capital budgeting process to create value for
19 ratepayers.

VI. GIP Programs That Should Be Rejected Pending Further Evaluation

20 **Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR**
21 **TESTIMONY.**

²⁸ DEC response to NCJC DR 2-4, attached as Stephens Exhibit 8.

²⁹ DEC response to NCSEA DR 2-19 (b), attached as Stephens Exhibit 9.

1 A. In this section of my testimony, I will describe GIP programs that should be
2 rejected pending further evaluation, because critical evaluations are missing that
3 will require extensive effort beyond the scope of this proceeding. I will also
4 identify opportunities for a transparent, stakeholder-engaged distribution planning
5 and capital budgeting process to deliver value when considering these types of
6 programs. Programs that should be rejected pending further evaluation include:

- 7 • Enterprise Communications Mission Critical Voice, Data (\$52.5, \$107.1
8 million);
- 9 • Distribution Automation (\$194.3 million); and
- 10 • Transmission System Intelligence (\$86.4 million).

11 A. *Mission Critical Voice and Data Network Programs*

12 **Q. WHAT CRITICAL EVALUATIONS ARE MISSING FROM DUKE**
13 **ENERGY'S PROPOSED VOICE AND DATA NETWORK**
14 **DEVELOPMENT PROGRAMS?**

15 A. Witness Alvarez describes the evaluations missing from these proposed programs,
16 so I will not repeat those here. While neither Witness Alvarez nor I are
17 communications experts, I appreciate his concern that Duke Energy completed no
18 technical or economic make vs. buy evaluation of alternatives to Duke Energy's
19 \$160 million proposal to build proprietary voice and data communication
20 networks. In this Internet of Things age, when public wireless carriers are
21 introducing high data transfer rates, dedicated bandwidth, and ever-improving
22 cybersecurity capabilities, it seems more than appropriate to me that an in-depth
23 evaluation of Duke Energy's claimed voice and data requirements, along with
24 potential options to satisfy them, be conducted. Stakeholders may need to enlist

1 expert services to properly participate in such an effort, but that seems preferable
2 to “waving through” a \$160 million investment that has not been thoroughly
3 evaluated. Due to the lack of technical or economic make vs. buy analyses, I
4 agree with Witness Alvarez that this GIP program be rejected pending a more
5 thorough evaluation.

6 *B. Distribution Automation and Transmission System Intelligence Programs*

7 **Q. WHAT CRITICAL EVALUATIONS ARE MISSION FROM THE**
8 **DISTRIBUTION AUTOMATION AND TRANSMISSION SYSTEM**
9 **INTELLIGENCE PROGRAMS?**

10 A. Duke Energy provides no benefit-cost analyses for these programs, claiming they
11 are “modernization” programs. I do not understand why categorizing them as
12 modernization programs excuses Duke Energy from the obligation to conduct
13 benefit-cost analyses. Indeed, in GIP descriptions of these programs,
14 improvements in reliability and resilience are featured. For all other GIP
15 programs in which improved reliability and resilience are claimed, benefit-cost
16 analyses were developed; why not for these two programs?

17 I agree that benefits can be difficult to quantify for some programs, and
18 that some programs merit approval without a benefit-cost analysis, or with a
19 negative benefit-cost analysis. Indeed, I categorized several GIP programs as
20 “merit approval with conditions” despite the lack of a benefit-cost analysis.
21 However, it seems to me that anticipated reliability and/or resilience benefits
22 should be quantified for any program that is promoted as beneficial to these
23 outcomes. Failure to quantify the benefits of programs that offer quantifiable
24 benefits represents a lack of accountability for benefit delivery. I therefore

1 recommend the Commission reject these programs until Duke Energy completes
2 benefit-cost analyses for them.

VII. Summary and Recommendations

3 **Q. PLEASE SUMMARIZE YOUR TESTIMONY AND**
4 **RECOMMENDATIONS.**

5 A. I began my testimony with context, describing how utilities have conducted
6 distribution planning to incorporate new technologies and technical challenges for
7 over a century. I then discussed how investor-owned utilities are changing their
8 approach from distribution planning to a focus on maximizing capital investment.
9 I presented historical evidence indicating that the reliability of Duke Energy's grid
10 in North Carolina has deteriorated significantly in recent years despite dramatic
11 increases in grid investment, confirming locally the phenomenon Witness Alvarez
12 describes nationally: grid reliability does not necessarily improve with grid
13 investment.

14 My testimony then continued with critical evaluations of the individual
15 programs or sub-components that make up Duke Energy's GIP. My testimony
16 placed Duke Energy's GIP programs and sub-components into one of five
17 categories: (1) Those that merit approval with conditions; (2) Those that only
18 merit approval with material modifications and conditions; (3) Those that do not
19 merit approval due to lack of cost-effectiveness/compliance with standard
20 industry practices; (4) Those that merit rejection pending further evaluation; and
21 (5) Those being considered in other dockets. I justify categorization through
22 testimony which evaluates the relative merits of each GIP program and sub-

1 component relative to costs, or identifies missing information prohibiting such
2 evaluation. My testimony also describes the general conditions I recommend the
3 Commission establish for any GIP program it approves, and modifications
4 specific to the self-optimizing grid and transmission hardening & resilience
5 programs. My testimony concludes with recommendations for the Commission's
6 consideration, including both primary and secondary (program-specific)
7 recommendations.

8 My primary recommendation, consistent with Witness Alvarez's
9 recommendation, is for the Commission to reject Duke Energy's GIP. Instead, I
10 recommend the Commission establish a proceeding to develop a transparent,
11 stakeholder-engaged distribution planning and capital budgeting process. Witness
12 Alvarez's testimony provides additional descriptions and justifications for such a
13 process. In the event the Commission rejects my primary recommendation, I
14 recommend the Commission follow my program-specific guidance as secondary
15 recommendations. I also describe conditions I recommend the Commission
16 establish for any GIP programs approved, including (1) performance
17 measurement; (2) cost caps and associated operating audits; and (3) rejection of
18 cost recovery for assets placed into service in the test year that are not standard
19 industry practice/not cost effective. I also recommended the Commission reject
20 deferral accounting because I believe the practice encourages investment in sub-
21 optimal grid programs. My testimony describes why many GIP programs are
22 sub-optimal.

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

1 A. Yes, it does. However, I may seek to supplement this testimony, either by filing
2 or during the evidentiary hearing, after seeing a demonstration of how Duke
3 Energy used the Copperleaf C55 software to develop transmission hardening and
4 restoration program benefit estimates.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Dennis Stephens on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and North Carolina Sustainable Energy Association either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of February, 2020.

s/ Gudrun Thompson

Gudrun Thompson