BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)	**TESTIMONY OF PAUL J.**
	)	**ALVAREZ ON BEHALF OF THE**
Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)	**NORTH CAROLINA JUSTICE**
	)	**CENTER, NORTH CAROLINA**
	)	**HOUSING COALITION, NATURAL**
	)	**RESOURCES DEFENSE COUNCIL,**
	)	**SOUTHERN ALLIANCE FOR**
	)	**CLEAN ENERGY AND THE**
	)	**NORTH CAROLINA**
	)	**SUSTAINABLE ENERGY**
	)	**ASSOCIATION**

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April 13, 2020

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Alvarez Exhibit 3: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-24, Docket No. E-7, Sub 1214, February 11, 2020 & Duke Energy Progress Response to NCJC et al. 5-22, Docket No. E-2, Sub 1219.

Alvarez Exhibit 4: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-1, Docket No. E-7, Sub 1214, February 10, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et al*., Data Request 5-1, Docket No. E-2, Sub 1219, February 10, 2020.

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Alvarez Exhibit 19: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, et al., Data Request 2-16, Docket No. E-7, Sub 1214, November 25, 2019.

I. Introduction

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My full name is Paul J. Alvarez. My business address is Wired Group, Post Office Box 620756, Littleton, Colorado, 80162.

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

A. I am the President of the Wired Group, a consultancy specializing in distribution utility investment, performance, and value creation.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree from the Kellogg School of Management at Northwestern University in 1991. My first role in the electric utility industry, beginning in 2001, was as a product development manager with Xcel Energy. I oversaw the development of new demand-side management ("DSM") programs, as well as programs and rates in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

After seven years with Xcel Energy, I established a utility practice for sustainability consulting firm MetaVu. While at MetaVu I utilized my DSM evaluation, measurement and verification ("EM&V") experience to lead two comprehensive evaluations of smart grid deployment performance, including both grid and meter modernization. The first was an evaluation of the SmartGridCity™ deployment in Boulder, Colorado completed for Xcel Energy and filed with the

Colorado Public Utilities Commission in 2010,[1] and the second was an evaluation of Duke Energy's Cincinnati-area deployment completed for the Ohio Public Utilities Commission in 2011.[2]

I started the Wired Group in 2012 to focus exclusively on distribution utility performance measurement and ratepayer value creation. In addition to leading the Wired Group, I teach, publish and present at conferences on related topics.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes, I testified on behalf of the Environmental Defense Fund in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, the most recent Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") rate cases regarding the Companies' "Power/Forward" grid investment plan. I also submitted testimony on on Duke Energy's Grid Improvement Plan, covering both DEC and DEP in Docket E-7 Sub 1214. Because the Grid Improvement Plan covered both Companies, my testimony herein is virtually identical to that testimony.

My testimony in those cases supported the need for distinct proceedings to develop grid modernization plans, and recommended that stakeholder engagement be utilized to better align the Companies' grid modernization plans and investments

[1] *SmartGridCity™ Demonstration Project Evaluation Summary*. Exhibit MGL-1 to the testimony of Michael G. Lamb in the Matter of the Public Service Company of Colorado Application for Approval of SmartGridCity Cost Recovery. Filed with the Colorado PUC in 11A-1001E on December 14, 2011. Alvarez et al. Report dated October 21, 2011.

[2] *Duke Energy Ohio Smart Grid Audit and Assessment*. Public Utilities Commission of Ohio Staff Report, public version, filed in 10-2326-GE-RDR on June 30, 2011. Alvarez et al.

with stakeholder priorities, and to increase plan cost-benefit ratios for ratepayers, communities, and the environment.

Q. DID THIS COMMISSION ACCEPT YOUR RECOMMENDATION IN THAT REGARD?

A. Yes, in part. As stated in the Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued in Docket No. E-7, Sub 1146, "the Commission directs DEC to utilize an existing proceeding, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission, and to engage and collaborate with stakeholders to address the myriad of issues raised in the context of Power Forward and the Company's proposed Grid Rider."[3]

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

A. Yes. I have testified before state utility regulatory commissions in California, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, North Dakota, Ohio, Pennsylvania, and Washington. I have also served clients participating in regulatory proceedings in Colorado, Hawaii, South Carolina, and Virginia. I also co-authored, with Dennis Stephens, a paper on Duke Energy's GIP from the perspective of South Carolina ratepayers,[4]

[3] *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction.* North Carolina Utilities Commission Docket No. E-7, Sub 1146 (June 22, 2018), p. 149.

[4] Alvarez P and Stephens D. *Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers.* Whitepaper developed for GridLab. January 11, 2019.

and a similar paper on Dominion's "Grid Transformation Plan."[5] (I note the Virginia SCC largely rejected Dominion's Grid Transformation Plan.)[6] The subject matter in all these proceedings related to utility planning, investment, and performance measurement. My full CV is attached as Alvarez Exhibit 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony critiques the Grid Improvement Plan ("GIP"), a multi-billion-dollar portfolio of investments in the transmission and distribution grid proposed by DEC and DEP (collectively, the "Companies" or "Duke Energy"). The GIP, as proposed in DEC's application in this docket, includes investments in both the DEC and DEP grids.[7] My testimony focuses on the cost-benefit analyses for the GIP, and the testimony of Dennis Stephens focuses on the technical aspects of the GIP.

Q. WHAT IS DUKE ENERGY ASKING THE COMMISSION TO APPROVE WITH REGARD TO THE GIP?

A. Although the testimony and exhibits of DEC Witness Jay Oliver, the Company's primary GIP witness, run over 600 pages, not including workpapers, and provide details on billions of dollars in proposed investments, DEC's application really requests just two GIP-related items: (1) a return on and of capital for GIP assets placed in service during the test year; and (2) deferred accounting on GIP assets placed into service from 2020 through 2022.

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[5] Alvarez P and Stephens D. *Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders*. Whitepaper developed for GridLab. October 5, 2018.

[6] Virginia State Corporation Commission PUR-2018-00100. Order dated January 17, 2019.

[7] Because the GIP as proposed is a package of investments in both the DEC and DEP grids, I have not attempted to disentangle DEC's investments from the package, and as a result, my testimony generally refers to the "Duke Energy" GIP.

Q. HOW IS THE CURRENTLY PROPOSED GIP DIFFERENT FROM THE "POWER/FORWARD" PROPOSAL THAT WAS REJECTED BY THIS COMMISSION?

A. To some extent, the GIP is a scaled-down version of "Power/Forward." Like Power/Forward, Duke Energy proposes to invest billions of dollars in its grid if the Commission grants its preferred cost recovery. Though the GIP is shorter (three years instead of 10) and the total capital cost is lower, nothing precludes Duke Energy from making additional proposals that could equal or exceed Power/Forward in the future. There is less spending on Targeted Undergrounding, though several new programs have been added that, as Witness Stephens' testimony indicates, suffer from the same deficiencies, as they are neither cost-effective nor standard industry practice. I welcome the addition of an integrated Volt-VAR control program (for conservation voltage reduction), though no cost-benefit analysis has been prepared for other added programs.

II. Summary and Recommendations

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony begins with context, documenting the lack of a relationship between distribution investments and reliability improvements by United States investor-owned utilities ("IOUs") in recent years. My testimony then provides evidence that the GIP will ultimately cost ratepayers $8.6 billion over 30 years, or $3.4 billion in present value terms. This is almost 50% greater than the $2.3 billion capital investment Duke Energy presents,[8] resulting from:

[8] *Direct Testimony of Jay Oliver*, Docket No. E-7, Sub 1214 ("*Oliver Direct*"), Exhibit 10, p. 3, "Capital Budget Summary – NC Only".

- $424.5 million in capital detailed in GIP cost-benefit analyses but not recognized in the 2020-2022 GIP capital schedule;
- $192.5 million in capital for Energy Storage and Electric Transportation presented as GIP programs but not included in 2020-2022 GIP capital schedule totals;
- $1.1 billion in software and communications network replacements during the 30-year GIP benefit period not included in the GIP capital or cost-benefit analyses ($405 million in present value); and
- $4.5 billion in carrying charges ratepayers will have to pay on GIP investments over the next 30 years.

My testimony also warns against the setting of precedents that will result in more sub-optimal capital spending in future years, the ambiguity of GIP capital cost estimates, and the lack of technical or economic "make vs. buy" analyses for $160 million in communications network investment as the "Internet of Things" era approaches.

My testimony then explains how Duke Energy overstates the benefits of the GIP by billions of dollars. My concerns include:

- A variety of aggressive and unsupported assumptions used to calculate many program-specific reliability improvement estimates;

- The manner in which Duke Energy translates reliability improvement estimates into economic benefits, using deeply flawed DOE "cost of service interruptions" data;
- The use of inflated primary benefits related to reliability as IMPLAN economic development model inputs, resulting in inflated secondary benefit estimates; and
- The failure of Duke Energy to estimate the detrimental impact of GIP rate increases on North Carolina's economy.

Based on these observations, I conclude that the GIP is a break-even proposition *at best* for ratepayers overall, and is dramatically negative for residential ratepayers in particular. This is because Duke Energy justifies its GIP almost entirely through reliability benefits that will accrue to commercial and industrial ("C&I") ratepayers. I also conclude that the GIP's asymmetrical risk profile, with ratepayers taking all risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios, is inappropriate.

Finally, my testimony examines the superficial nature of Duke Energy's stakeholder engagement efforts, comparing those efforts to a truly transparent, stakeholder-engaged distribution planning and capital budgeting process designed to better align utility, ratepayer, and stakeholder interests. The North Carolina economy's ability to accommodate rate increases is finite, and therefore, Duke Energy grid investments must be contained, and capabilities carefully prioritized, such that the right capabilities are available to an appropriate geographic extent at the right time. Given that rate increases are a finite resource, capital spent poorly today makes less capital available tomorrow for investment in the grid-related components of the North Carolina Clean Energy Plan.[9]

Q. WHAT QUESTIONS DO YOU BELIEVE ARE RAISED BY THE PROPOSED GIP?

A. I believe the key question for the Commission and ratepayers is whether the GIP, if approved, will deliver benefits to North Carolina ratepayers and communities in excess of costs to ratepayers and communities. My testimony, combined with Witness Stephens's testimony, will help answer this question. In addition, a number of other important questions are prompted by Duke Energy's GIP proposal:

- What is the appropriate balance between affordability and reliability?
- What amount of reliability and resilience should be expected, with associated cost socialization across all ratepayers, versus the amount of reliability and resilience self-insurance individual consumers should be expected to fund based on individual risks and tolerances?
- What is the appropriate investment balance between weather event resilience in the short term and reduction of greenhouse gas emissions impacting the climate in the long term, in line with the state's Clean Energy Plan and Duke Energy's own carbon reduction goals?

[9] State Energy Office, Department of Environmental Quality. *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System.* October, 2019.

- How do the cost and risk of grid investments to accommodate third-party investments in clean distributed energy resources ("DER") compare to the cost and risk of Duke Energy investments in clean generation?

- What is the most appropriate way to evaluate capital-intensive Duke Energy proposals against the purchase of non-capital services from third parties?

- How much of a rate increase due to distribution investments can the North Carolina economy absorb without undue harm to companies, employment, and communities?

These questions should not—and cannot—be answered solely by Duke Energy. Instead, I suggest a truly transparent distribution planning and capital budgeting process, complete with significant and thorough stakeholder input and decision rights, should be employed to answer them. Such a process would help to optimize grid investment in a way that best balances utility, ratepayer, community and stakeholder goals, priorities, and interests.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION IN THIS PROCEEDING?

A. Due to the significant deficiencies and opportunities for improvement described in my testimony, my primary recommendation is that the Commission reject Duke Energy's GIP, and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process for future use in North Carolina. I recommend that upon completion, the new process be used to develop a grid improvement plan that better aligns Company, ratepayer, and stakeholder interests.

Should the Commission reject my primary recommendation, I recommend it adopt the program-specific recommendations Witness Stephens describes as secondary recommendations in his testimony. I concur with all conditions and adjustments Witness Stephens describes for those GIP programs the Commission might approve. Finally, like Witness Stephens, I believe that deferred accounting treatment of GIP costs is unnecessary, and encourages sub-optimal grid investments of the types Witness Stephens identifies in his testimony. Therefore, I recommend the Commission reject DEC's request for deferral of costs for any GIP program the Commission might approve.

III. Historical Context

Q. PLEASE PROVIDE THE HISTORICAL CONTEXT YOU MENTIONED REGARDING DECLINING RELIABILITY DESPITE INCREASING INVESTMENTS IN THE GRID.

A. United States IOUs have increased distribution grid investment by 24% since 2013 despite flat or falling energy use and demand.[10] Over the same period, two key indices of reliability have declined: System Average Interruption Duration Index ("SAIDI")[11] has deteriorated 9%, and System Average Interruption Frequency Index ("SAIFI")[12] has deteriorated 6%.[13] (Note that for SAIDI and SAIFI, lower values represent greater reliability.) This data is presented in Figure 1 below.

[10] FERC Form 1 data as summarized by the Utility Evaluator, available by subscription at www.utilityevaluator.com.

[11] SAIDI, a measure of service interruptions duration per IEEE Standard 1366.

[12] SAIFI, a measure of service interruption incidence per IEEE Standard 1366.

[13] US Energy Information Administration. Data submitted by US investor-owned utilities on Form 861 as summarized by the Utility Evaluator.

Figure 1: Relationship Between Grid Investment and Reliability Without Major Events, U.S. IOUs

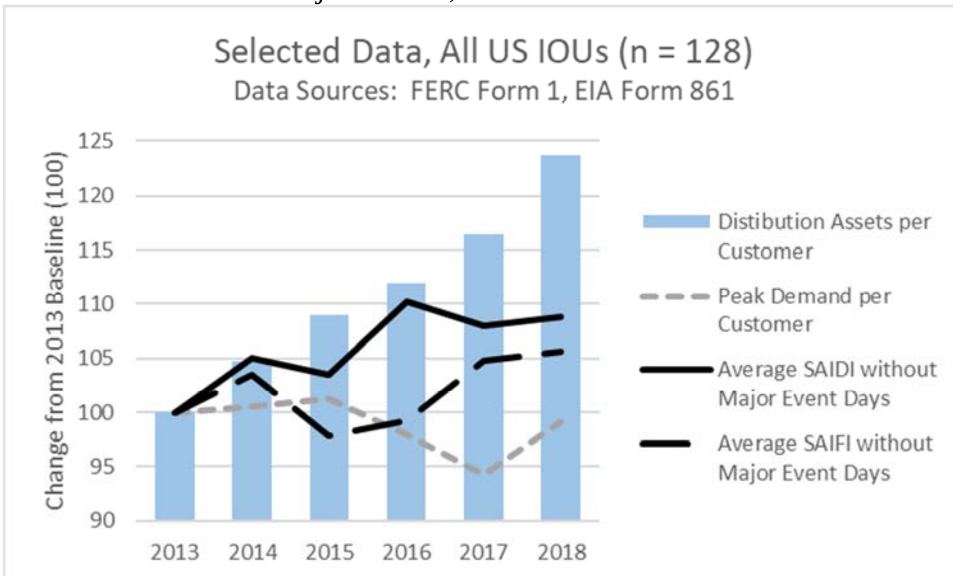

Figure 1 illustrates a counterintuitive caution to regulators: increased distribution investment is not correlated with reliability improvements. This conclusion is consistent with a Department of Energy study on U.S. electric reliability covering years 2002 to 2012.[14] Figure 1 analyzes "clear day" reliability; that is, without major events.[15] Figure 2, below, shows the same comparison, but using reliability measures that include major events. The relationship between distribution investment and improved resilience in the face of major events is even more tenuous than the relationship between distribution investment and clear-day reliability.

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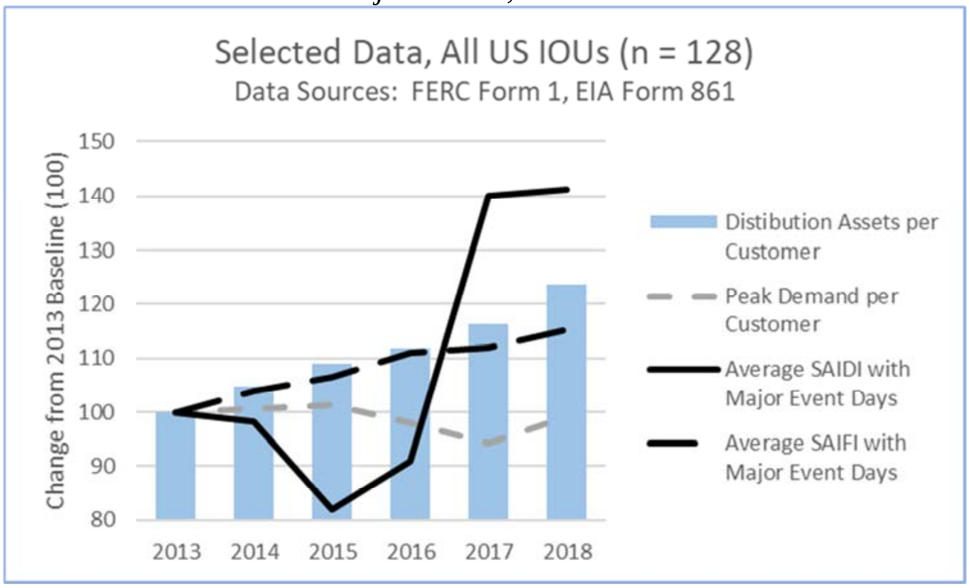
[14] Larsen P, LaCommare K, Eto J, and Sweeny J. *Assessing Changes in the Reliability of the U.S. Electric Power System.* Lawrence Berkeley National Laboratory study for the U.S. Department of Energy. August, 2015. P. 37.

[15] "Major events" are almost exclusively severe weather events. Though rare, transmission-level outages outside of distribution utilities' control are also counted as "major events."

Figure 2: Relationship Between Grid Investment and Reliability With Major Events, U.S. IOUs



Q. DO YOU CONCLUDE FROM THIS DATA THAT INVESTMENTS IN RELIABILITY OR WEATHER RESILIENCE ARE BAD IDEAS?

A. No. Instead, I believe any of the following may be true: (1) IOU distribution investments have not been focused on the capabilities most likely to improve reliability and resilience; (2) IOU distribution investments have been focused on improving reliability and resilience, but are not succeeding; (3) IOUs, recognizing that deteriorating reliability can help justify large distribution investments, are more accurately reporting poor reliability performance; and/or (4) weather events really are getting more frequent and severe. Proposed grid investments, and in particular grid investment proposals developed outside of the distribution planning processes Witness Stephens describes in his testimony, must be very carefully evaluated and prioritized if benefits to ratepayers are to exceed costs to ratepayers.

IV. The GIP Understates Costs to Ratepayers by Billions of Dollars

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. The $2.3 billion North Carolina capital budget Duke Energy presents in its GIP[16] understates costs to ratepayers by almost 50%:

- $424.5 million in capital is detailed in GIP cost-benefit analyses but not recognized in the 2020-2022 GIP capital schedule;
- $192.5 million in capital for Energy Storage and Electric Transportation presented as GIP programs are not included in 2020-2022 GIP capital schedule totals;
- $1.1 billion in software and communications network replacement cost during the 30-year GIP benefit period are not included in capital budgets or cost-benefit analyses ($405 million in present value terms); and
- $4.5 billion in carrying charges ratepayers will have to pay on GIP investments over the next 30 years are not included in ratepayer costs.

Other issues related to GIP costs concern me. First is the potential establishment of unwarranted program precedents, particularly as the GIP proposes no program performance measurement. Second is the ill-defined nature of program costs, as illustrated by differences between program capital budgets and cost-benefit analyses. Finally, I am concerned by the significant cost, and insufficient

[16] Oliver Direct, Ex. 10, p. 3, "Capital Budget Summary – NC Only".

evaluation of options, related to $160 million in capital for new voice and data communications networks Duke Energy proposes.

Q. HOW HAVE YOU DETERMINED THAT DUKE ENERGY'S GIP CAPITAL BUDGET IS UNDERSTATED BY $424.5 MILLION IN CAPITAL SPENDING PLANNED OUTSIDE THE THREE-YEAR PLAN PERIOD?

A. Duke Energy provided cost-benefit analyses for most of the programs listed in the $2.3 billion North Carolina GIP Capital Budget Summary.[17] Notably, the capital spending in the cost-benefit analyses is significantly greater than the capital identified in the North Carolina GIP capital budget summary. This is concerning, as it appears that the primary GIP benefits that Duke Energy projects ($9.241 billion)[18] will require much more capital than Duke Energy presents in the GIP ($2.3 billion).

Q. WERE YOU ABLE TO EXPLAIN THE DIFFERENCE BETWEEN THE TWO ESTIMATES?

A. To some extent. For example, the totals in the North Carolina GIP Capital Budget Summary did not include $192.5 million in Energy Storage and Electric Transportation program capital (more on that below). In addition, the cost-benefit analyses for some programs, such as Transmission programs, included capital for both North and South Carolina. After adjusting for these factors, however, the capital specified in the cost-benefit analyses was still much larger than presented in the GIP capital budget summary.

Q. WERE YOU ABLE TO IDENTIFY THE REMAINING DIFFERENCES BETWEEN THE CAPITAL IN THE COST-BENEFIT ANALYSES AND THE CAPITAL IN THE GIP CAPITAL BUDGET SUMMARY?

[17] Oliver Direct, Ex. 7, multiple Microsoft Excel® workbooks.

[18] Oliver Direct, Ex. 8, page 3.

A. Yes, and I categorize them into three "buckets" of spending. The first bucket is $234.4 million in program capital spending planned in the cost-benefit analyses prior to the 2020-2022 period covered by the GIP capital budget summary. The second bucket consists of differences I was unable to reconcile during the GIP capital budget period years of 2020-2022. I found the capital in the cost-benefit analyses differed from the capital presented in the GIP capital budget for multiple programs. Some programs had much more capital in the GIP than in the corresponding cost-benefit analyses, but for other programs the reverse was true. These differences concern me, as I will discuss further below, but the net of these differences is that the capital in the 2020-2022 GIP capital budget summary exceeds the capital in the cost-benefit analyses by $53.5 million. The third bucket consists of spending beyond the GIP capital budget period, amounting to $243.6 million from 2023 to 2027, and consisting mainly of integrated volt-VAR control, transmission hardening & resilience, and targeted undergrounding program capital. In total, the capital spending required to secure the benefits projected in the cost-benefit analyses, including $192.5 million in energy storage and electric transportation capital missing from GIP capital budget totals, is $616.9 million (26.6%) higher than the $2.319 billion presented in the North Carolina 2020-2022 GIP capital budget summary.

Q. DO YOU FIND IT PROBLEMATIC THAT DEP DID NOT INCLUDE THE $192.5 MILLION ENERGY STORAGE AND ELECTRIC TRANSPORTATION CAPITAL IN NORTH CAROLINA GIP CAPITAL BUDGET TOTALS?

A. To me, it simply illustrates another example of DEP underestimating GIP costs. It is true that these programs are being evaluated in other dockets. However, as DEC describes these programs as part of its GIP,[19] and as ratepayers will be required to pay for these programs if approved, I believe it is appropriate to include capital from these programs as part of the costs DEP ratepayers will have to pay for discretionary spending that is outside "business as usual." It seems disingenuous to me to describe these as GIP programs, but to exclude their costs from GIP capital program totals.

Q. EXPLAIN WHY DUKE ENERGY'S FAILURE TO INCLUDE COSTS TO REPLACE SHORT-LIVED ASSETS, SUCH AS SOFTWARE AND COMMUNICATIONS INFRASTRUCTURE, UNDERSTATES COST BY $1 BILLION.

A. Field hardware assets in Duke Energy's GIP generally have an estimated useful life of at least 25-35 years. As is appropriate, Duke Energy estimated benefits for each program individually, based on the expected 25-35 year useful life of program assets. The exceptions are software and communications networks, which have useful lives of 5-10 years.[20] Presumably, communications networks and software are essential to securing the benefits Duke Energy projects in program cost-benefit analyses; otherwise, they would not be included in the GIP (new data and voice communications networks are even described as "Mission Critical").

Unfortunately, GIP cost-benefit analyses include no capital costs for replacements of these communication networks and software packages, with useful

[19] Oliver Direct, Ex. 4, pages 13-15, and Ex. 10, pages 3, 47, and 84.

[20] DEC Response to NCJC Data Request No. (hereinafter, "NCJC DR") 5-3, NCUC Docket No. E-7, Sub 1214, attached as Alvarez Exhibit 2. (References to DEC responses to data requests are to those served in NCUC Docket No. E-7, Sub 1214.)

lives of 5-10 years, over the course of the 25-35 year benefit periods assumed in the cost-benefit analyses, thus resulting in a significant cost understatement. As shown in Table 1, below, and assuming a 2.5% compound annual inflation rate, I estimate the understatement to be at least $1 billion, or $405.3 million in present value terms (discounted at Duke Energy's 6.8% weighted average cost of capital).

Table 1: Software and Communications Network Capital Costs Missing from Duke Energy GIP Cost-benefit Analyses

Program/Sub-Component	Present Value	2027	2032	2037	2042	2047
ADMS (Self-Optimizing Grid)	53,722,192	-	62,369,028	-	79,837,629	-
Enterprise Communications	233,553,437	-	271,144,948	-	347,088,457	-
Enterprise Applications	78,380,613	31,506,325	35,646,514	40,330,759	45,630,552	51,626,781
ISOP Programs	18,717,674	7,523,865	8,512,562	9,631,183	10,896,799	12,328,728
DER Dispatch Tool	20,960,980	8,425,597	9,532,790	10,785,476	12,202,777	13,806,322
Total	405,334,895	47,455,786	387,205,842	60,747,418	495,656,214	77,761,831

Q. PLEASE SUM UP THE AMOUNTS YOU HAVE IDENTIFIED THAT ARE MISSING FROM THE GIP CAPITAL BUDGET SUMMARY.

A. I have identified $1.0 billion in capital, including $616.9 million in program capital and $405 million (present value) in communications network and software replacement capital that is missing from Duke Energy's $2.3 billion budget.

Q. HAVE YOU ESTIMATED THE REVENUE REQUIREMENT OF THE GIP?

A. Yes. Using assumptions that DEP employed to calculate its revenue requirement in this rate case,[21] I estimated the revenue requirements associated with GIP capital and O&M spending as presented in program cost-benefit analyses, plus the capital

[21] Direct Testimony of Kim H. Smith, NCUC E-2 Sub 1219 ("Smith Direct"), Exhibit 1, Tab "Pg 2".

budgets of programs for which no cost-benefit analyses were completed (including energy storage and electric transportation), plus the missing communications and software replacement costs described above. The highlights of my calculations are presented in Alvarez Exhibit 10. I estimate the total GIP revenue requirement over 30 years to be $8.6 billion, or $3.4 billion in present value terms.[22] This is almost 50% higher than the $2.3 billion Duke Energy presents as the capital cost of the program in the GIP capital budget. If the Commission is interested in comparing the present value of GIP program benefits to GIP ratepayer costs, I recommend it use my $8.6 billion nominal cost estimate, or my $3.4 billion present value estimate, in place of the $2.3 billion found in the GIP capital budget.

Q. WHAT DOES THIS MEAN IN TERMS OF RATE INCREASES?

A. In this rate case DEP is requesting annual revenues of $3.9 billion, including $992 million in fuel (and purchased power) costs.[23] According to my estimate, the GIP revenue requirement will peak in 2023 at $358.6 million. If the GIP revenue requirement is split by customer count between DEC (2.005 million) and DEP (1.412 million), the DEP revenue requirement will be 41.3% of the total, or $148.1 million. This is a 3.8% increase in the DEP revenue requirement and a 5.0% increase in the DEP non-fuel revenue requirement. Given that these GIP rate

[22] In my DEC testimony, I used DEC assumptions to estimate GIP revenue requirements, including DEC's weighted average cost of debt (4.51%). To be consistent, when estimating revenue requirements in this DEP testimony, I used DEP assumptions to estimate GIP revenue requirements. According to DEP Witness Smith Direct Testimony, Exhibit 1, page 2, DEP's weighted average cost of debt is slightly lower than DEC's, at 4.15%. This explains why there are very slight differences in the GIP revenue requirement (and related values) I estimated in this DEP testimony relative to the estimate found in my DEC testimony

[23] Smith Direct, Exhibit 1, tab “Exhibit 1 Pg 1”, column 6.

increases will be in addition to whatever other increases DEP requests for business-as-usual cost increases, I conclude that the rate increases resulting from the GIP will be significant.

Q. YOU MENTIONED A CONCERN ABOUT THE INVESTMENT PRECEDENTS THAT APPROVING DEFERRAL ACCOUNTING FOR THE GIP WOULD ESTABLISH. PLEASE EXPLAIN.

A. Although the proposed GIP capital investment is large, each program replaces just a fraction of the installed base of assets of the type targeted by each program. My concern is that, once deferral accounting is approved for a program, the approval will be interpreted as tacit endorsement of the technical or economic merits of the program. This GIP may be only the first of several extraordinary grid investment proposals the Commission will be asked to consider in the next decade, and these proposals are likely to consist largely of continuations of previously approved programs. The fact that the GIP is, in many ways, a 3-year, $2.3 billion subset of the 10-year, $13 billion Power/Forward plan proposed in the last Duke Energy rate cases should cause the Commission significant concern in this regard. If the Commission approves the GIP in its entirety, the number of assets remaining available for future replacement are listed in Table 2, below.

Table 2: Assets Still Available for Replacement if the GIP Is Approved

Program (count of target assets replaced per cost-benefit analyses)[24]	Assets remaining Count (Percent)
Targeted Undergrounding (235 backyard line miles)[25]	Unknown; likely in excess of 90%
44kV Lines (80 miles)[26]	2,720 (97.1%)
Transformer Bank Replacement (151 substation transformers)[27]	5,766 (97.4%)
Oil-filled Circuit Breaker Replacement (1,365 substation breakers)[28]	3,285 (70.6%)
Substation physical security (27 substations)[29]	2,098 (99.2%)

Q. YOU MENTION THAT GIP COSTS ARE "ILL-DEFINED." PLEASE SUPPORT THIS CLAIM, AND EXPLAIN WHY IT CONCERNS YOU.

A. As I mentioned earlier, there are many differences between the capital costs provided in the GIP capital budget and the total capital costs found in GIP cost-benefit analyses. As just one of many examples, the GIP capital budget for "Oil

[24] Oliver Direct, Ex. 7, multiple Microsoft Excel® workbooks.

[25] DEC and DEP do not track miles of line through residential backyards. DEC Response to NCJC Data Request 8-24 and DEP Response to NCJC Data Request 5-22, attached as Alvarez Exhibit 3. (References to DEP responses to data requests are to those served in the current docket.) My assessment that the proportion of backyard overhead line miles yet to be undergrounded is "likely well over 90%" is based on an estimate that the program proposes to underground just 235 miles ($200 million in capital cost divided by $850,000 per mile, from Oliver Direct Ex. 7 workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx"), while Duke Energy is thought to have thousands of miles of backyard overhead lines.

[26] DEC Response to NCJC Data Request 8-1; and DEP Response to NCJC Data Request 5-1, attached as Alvarez Exhibit 4.

[27] DEC Response to NCJC Data Request 8-26; and DEP Response to NCJC Data Request 5-17, attached as Alvarez Exhibit 5.

[28] DEC Response to NCJC Data Request 8-25; and DEP Response to NCJC Data Request 5-16, attached as Alvarez Exhibit 6.

[29] DEC Response to NCJC Data Request 2-5, attached as Alvarez Exhibit 7.

Breaker Replacement" is just over $200 million;[30] the capital provided in cost-benefit analyses, after removing portions that apply to South Carolina, is only $106.6 million.[31] This is significant, particularly as Duke Energy never really specifies how much the GIP program will cost.[32] If deferral accounting is approved, we do not know what DEP (or DEC) will spend on the GIP, or how the spending will be split among the programs. This ambiguity is extremely concerning to me, and I believe it should concern the Commission as well. How will the Commission be able to hold DEP accountable for Oil Breaker costs, when it does not know how many Oil Breakers Duke Energy will actually replace, or how much capital it will spend to do so? What governs Oil Breaker capital spending: the GIP capital budget, or the capital in the cost-benefit analysis? Further, changes to the mix of programs and capital within the GIP will impact GIP benefits; but if the mix changes, what is the corresponding impact to projected benefits? The cost caps and operating audits Witness Stephens recommends in his testimony will go a long way to improving Duke Energy GIP cost and benefit accountability in light of these ambiguities.

Q. PLEASE PROVIDE SUPPORT FOR YOUR ASSERTION THAT DUKE ENERGY DID NOT SUFFICIENTLY EVALUATE OPTIONS RELATED TO $160 MILLION IN CAPITAL FOR NEW VOICE AND DATA COMMUNICATIONS NETWORKS.

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[30] Oliver Direct, Ex 10, page 3, line "Oil Breaker Replacements".

[31] Oliver Direct Ex 7, "Trans_Oil Breaker_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx" (less 18.7% for South Carolina) and "Trans_Oil Breaker_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx" (less 9.3% for South Carolina).

[32] DEC Response to NCJC Data Request 5-4, attached as Alvarez Exhibit 8.

A. I believe the policy of evaluating potentially lower-cost third-party "non-wires alternatives" to capital investment in the grid should be extended to communications networks. In discovery, DEC admitted that Duke Energy had not evaluated alternatives to proprietary development and ownership of two new communications networks it wants to build, for voice and data communications,[33] at costs of $52 million and $107 million, respectively.

Q. DID YOU ASK DEC WHY ALTERNATIVES TO PROPRIETARY NETWORK DEVELOPMENT WERE NOT EVALUATED?

A. Yes. In discovery, the Company responded that third-party networks didn't meet minimum technical standards.[34] However, stakeholders have no way of knowing whether the technical standards are appropriate, or whether they have been set as an unnecessarily high bar, so as to make third-party satisfaction of them impossible. Given that Duke Energy is providing safe and reliable electric service with the voice and data communications networks it is already operating, it seems prudent to conduct a detailed investigation and evaluation before approving a $160 million capital investment. I note that this is precisely the kind of distribution investment decision that illustrates the value of a transparent, stakeholder-engaged distribution planning and capital budgeting process.

Q. WHY DO YOU QUESTION DUKE ENERGY'S STATEMENT THAT THIRD-PARTY NETWORKS COULDN'T MEET TECHNICAL STANDARDS?

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[33] DEC Responses to North Carolina Sustainable Energy Association Data Request Nos. (hereinafter, "NCSEA DR") 2-52 (d) and 2-53 (e), attached as Alvarez Exhibit 9.

[34] Ibid.

A. My concern is based on experience and anecdotal evidence, but at the very least, these point to the need for additional investigation and evaluation. For example, one critical utility concern is that in an emergency, third-party networks will be swamped with calls, making utility use of the network during a service restoration effort impossible. However, third parties' 4G cellular networks now offer "network slicing" capabilities that dedicate and reserve part of a physical network's bandwidth to various clients. AT&T's FirstNet service, developed specifically to meet the needs of first responders like police and fire departments, addresses this concern through network slicing. I also note that at least one state utility regulatory commission, Rhode Island, is questioning multi-hundred million dollar investments by a utility in a proprietary network when alternatives may be available.[35] I am also aware of at least two investor-owned utilities, Xcel Energy[36] and Hawaiian Electric,[37] that use public 4GLTE networks for at least some grid data communications. I note that non-profit utilities, which are not subject to capital bias, utilize third party networks to a much greater degree than investor-owned utilities do. The burden of proof that an investment is reasonable and prudent falls on utilities. When $160 million is proposed for services already available from

[35] Rhode Island PUC 4770 and 4780. Settlement Agreement dated June 6, 2018, page 49: "The Updated AMF Business Case for Rhode Island . . . will include an evaluation of shared communications infrastructure and various ownership models for key AMF components."

[36] Lysaker D and Markland D. *Xcel Energy Leverages 4G LTE to Enable Reliable, High Speed Connectivity to Distribution End Points.* Green Tech Media webcast July 31, 2017. (https://www.greentechmedia.com/webinars/webinar/xcel-energy-leverages-4g-lte-to-enable-reliable-high-speed-connectivit)

[37] Alleven, M. *Verizon taps Cat M1 network for smart grid utility services.* Fierce Wireless article posted July 19, 2018. (https://www.fiercewireless.com/wireless/verizon-taps-cat-m1-network-for-smart-grid-utility-services)

third parties, time spent evaluating reasonableness and prudency in advance is time well spent.

V. The GIP Overstates Benefits to Customers by Billions of Dollars

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. The GIP will deliver only a small fraction of the benefits that Duke Energy projects. First, Duke Energy overstates primary GIP economic benefits from reliability, at both the program-specific and systemic levels. Duke Energy also relies inappropriately on the IMPLAN model to estimate secondary, economic-development benefits of reliability improvements it attributes to the GIP. These benefits should be ignored entirely. Not only are they inflated, they do not take into account the detrimental impact to the North Carolina economy of the GIP rate increases discussed in the previous section of testimony. Further, the over-estimated benefits of some programs provide "cover" for programs that are not cost-effective. Although Duke Energy presents the GIP as a package, that package consists of programs that should be examined individually.

Q. PLEASE CHARACTERIZE THE GIP BENEFITS DUKE ENERGY PROJECTS.

A. Duke Energy projects two types of benefits from its GIP. Primary benefits are the direct benefits DEC, DEP or its ratepayers will receive directly, in the form of reliability improvements, O&M cost reductions, energy conservation, etc. Duke Energy projects the present value of these benefits, delivered over the next 30 years or so, to be $9.2 billion.[38] Duke Energy then adds follow-on, secondary benefits it projects will accrue to the North Carolina economy as a result of the primary benefits. Duke Energy calls these IMPLAN benefits, named after the tool used to calculate them, and estimates their present value at $7.2 billion.[39] I will critique the primary benefits first, and critique the IMPLAN benefits later in this section.

My critique of primary benefit estimates will focus on the economic benefits of anticipated reliability improvements, as these benefits constitute 88% of the GIP benefits Duke Energy projects.[40] It is important to understand that of these reliability-related benefits, Duke Energy estimates that more than 97% will accrue to Commercial and Industrial ("C&I") ratepayers.[41]

Q. HOW DOES DUKE ENERGY ESTIMATE THE ECONOMIC BENEFITS RELATED TO GIP RELIABILITY IMPROVEMENTS?

A. Duke Energy used a two-step process to estimate the economic benefits related to GIP reliability improvements. The first step is to estimate the impact of a program on the frequency of interruptions (customer interruptions, or "CI") and the duration of interruptions (customer minutes interrupted, or "CMI"), which is calculated by rate class on an asset-specific basis (such as a circuit). The second step is to translate these reliability improvements into economic benefits, by multiplying the projected CI or CMI reductions by rate class by estimates of economic impact per

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[38] Oliver Direct, Ex 8, page 3.

[39] Ibid.

[40] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7, attached as Alvarez Exhibit 10.

[41] Ibid.

CI or CMI by rate class.[42] The exception to this approach is for the projects that comprise the transmission hardening and restoration program. For those projects, the economic benefits from reliability improvements were calculated using Duke Energy's risk-informed investment decision support software, Copperleaf C-55,[43] which employs the same source for estimates of economic impact per CI or CMI that Duke Energy uses for all other reliability improvement benefit calculations.

Q. WHAT IRREGULARITIES IN THIS TWO-STEP RELIABILITY BENEFIT ESTIMATION PROCESS LEAD YOU TO CONCLUDE THAT DUKE ENERGY HAS OVERSTATED THESE BENEFITS?

A. Witness Stephens and I have identified multiple program-specific assumptions leading to overstated reliability improvement estimates in step 1 of the process. I have also identified multiple concerns with the underlying research that make its estimates of economic impact per CI or CMI unsuitable for use in translating reliability improvements into economic benefits in step 2 of the process. These irregularities indicate that the primary GIP benefit estimates provided in Duke Energy's cost-benefit analyses are dramatically overstated.

A. Program-Specific Assumptions Leading to Overstated Reliability Improvements

Q. PLEASE DESCRIBE THE PROGRAM-SPECIFIC ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES.

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[42] These estimates are based on a 2013 update of research completed in 2009 by Lawrence Berkeley National Laboratories ("LBNL") for the US Department of Energy ("DOE"). Sullivan M, Schellenberg J, and Blundell M. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. January, 2015.

[43] I note that neither Witness Stephens nor I were able to review this software, or how it was used to calculate the economic benefits of the transmission hardening and resilience program, in advance of the testimony due date.

A. Witness Stephens and I have identified multiple programs with inflated reliability improvement estimates, including transmission hardening and restoration, targeted undergrounding, long duration interruption/high impact sites, transformer bank replacement, and oil-filled breaker replacement programs. Duke Energy's cost-benefit analyses project that these five programs will deliver almost 75% of the GIP's reliability-based economic benefits.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE TRANSMISSION HARDENING AND RESTORATION PROGRAM.

A. The largest part of the transmission hardening and restoration ("TH&R") program, representing 83.2% of program costs and 95.5% of program benefits not related to substation flood mitigation,[44] consists of rebuilding DEP transmission lines, including new support structures and new static lines. In fact, Duke Energy projects the TH&R projects alone will amount to $1.899 billion in primary benefits, or 20.6% of all GIP benefits.[45]

Unlike the cost-benefit analyses for any other GIP programs/sub-components, Duke Energy calculated the reliability-related benefits of its TH&R program using a proprietary software program from Copperleaf, the C55 "Investment Decision Optimization Solution." One software feature is that "asset condition data and degradation curves can be modeled to determine the overall risk profile of your assets." The software is designed to help utilities work with

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[44] Oliver Direct, Ex 8, page 2,

[45] Ibid.

stakeholders to “quickly come to agreement on the best overall investment strategy.”[46]

My concern is that the C55 software, the data Duke Energy is inputting regarding asset condition, the asset degradation curves being employed, or some combination of these, is dramatically overstating transmission hardening and restoration benefits. For example, Witness Stephens believes strongly that asset degradation curves should be based solely on Duke Energy’s historical asset failure rates. In discovery, DEP stated that in the last five years it had only 10 static line failures out of 6,244 transmission line miles,[47] a failure rate of just 0.03% per line mile per year (3 in 10,000 likelihood). DEP also provided zero instances of pole failures in the last five years, the result of its highly effective, existing pole inspection program.[48] Assuming historical failure rates continue into the future – and DEP has provided no evidence as to why they should not – there is no possibility that the reliability benefits associated with just 2 static line failures every year for all of DEP, and zero pole failures every year for all of DEP, will provide the approximately $200 million in average annual primary reliability benefits required for a $1.899 billion present-value primary benefit estimate from the TH&R program.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE TH&R PROGRAM BENEFIT ESTIMATES DEVELOPED BY DUKE ENERGY THROUGH ITS USE OF THE COPPERLEAF C-55 SOFTWARE?

[46] Copperleaf C55 software brochure available at https://resources.copperleaf.com/brochures-2/c55-investment-decision-optimization

[47] DEP Response to NCJC Data Request 6-3(e), attached as Alvarez Exhibit 11.

[48] Ibid, 6-3(c).

A. Yes. The Copperleaf C-55 software estimated unreasonably high reliability improvement estimates from Duke Energy's TH&R program given historical actual transmission equipment failure rates. For example, the C-55 software estimates a transmission failure rate equal to 0.25% per span (between poles or towers, which averages 800 to 1,000 feet), per year,[49] or a likelihood of 25 out of 10,000 spans per year. Assuming an average of six spans per mile, this works out to a failure likelihood of 1.5% per mile per year (25/10,000ths per span X six spans per mile). Compare this to the historical actual transmission equipment failure rate Duke Energy provided in discovery, which was 85 failures in five years[50] over 2,800 (44kV) transmission line miles,[51] or a likelihood of 0.6% per mile per year (85 failures divided by five years divided by 2,800 miles). Thus, the Copperleaf C-55 approach to TH&R program benefit estimation assumes avoided service interruptions 2.5 times higher (150/60) than Duke Energy's historical actual transmission service interruptions due to equipment failure.

Furthermore, the Copperleaf C-55 approach assumed an improvement in "Redundancy Value" from the TH&R program. "Redundancy value" relates to the idea that a back-up transmission line could fail while being used in place of a line that has already failed. While Duke Energy's historical failure rate for transmission lines is 0.6% per mile per year per the above, the "redundancy value" used in the C-55 software is inexplicably set at 5.0% for radially served substations,[52] or almost

[49] DEP Response to NCJC Data Request 6-8(c), attached as Alvarez Exhibit 12.
[50] DEC Response to NCJC Data Request 8-28(a), attached as Alvarez Exhibit 13.
[51] DEC Response to NCJC Data Request 8-1(a), attached as Alvarez Exhibit 14.
[52] DEP Response to NCJC Data Request 6-9(c), attached as Alvarez Exhibit 15.

10 times higher than historical failure rates. This represents another clear example of exaggeration of TH&R program benefits.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE TARGETED UNDERGROUNDING PROGRAM.

A. Duke Energy projects $2.041 billion in present-value, or 22% of the total projected primary GIP benefits, will be delivered by the targeted undergrounding ("TUG") program.[53] Though the TUG program is dedicated to undergrounding overhead lines that currently run through residential backyards, Duke Energy's cost-benefit analyses project that over 98% of the benefits from targeted undergrounding will accrue to C&I ratepayers. Duke Energy claims that every fault in overhead lines in residential areas results in 2.7 momentary outages upstream of the fault, on portions of circuits with large numbers of C&I ratepayers. This 2.7:1 ratio is based on a relationship established by comparing the count of system-wide momentary interruptions to the count of system-wide sustained interruptions each year from 1997 to 2010.[54]

Not only is this ratio based on old data, no causal relationship has been established. In other words, it has not been shown that outages in specific residential areas cause momentary outages for upstream C&I ratepayers on the same circuit. It is inappropriate to base a benefit from specific projects on specific circuits and neighborhoods on a system-wide statistical relationship between

[53] Oliver Direct, Ex 8, column "Total NPV Benefits" (primary).

[54] DEC Responses to NCSEA DR 3-31 (attachment "1997-2010 DEC SAIFI and MAIFI.xlsx") and NCJC DR 5-32, attached as Alvarez Exhibit 16.

sustained and momentary outages for which no causation can be shown. If Duke Energy wishes to project upstream momentary outage avoidance for C&I ratepayers as a benefit of undergrounding, and to justify $114.5 million in investment on that basis, it should be required to provide historical momentary outage data specific to those circuits and upstream C&I ratepayers.

Q. DID YOU REQUEST HISTORICAL MOMENTARY OUTAGE DATA IN DISCOVERY?

A. Yes. Duke Energy stated that it does not even monitor momentary interruptions, and has not since 2010.[55] Therefore, Duke Energy cannot provide any data indicating that C&I ratepayers can realistically expect any reduction in momentary outages, let alone the sizes of those reductions. Nor can Duke Energy establish a baseline of pre-undergrounding momentary interruption data for subsequent evaluation of reliability improvements from targeted undergrounding. For all of these reasons, I believe the reliability improvement estimates Duke Energy projects from the TUG program to be vastly overstated.

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE LONG DURATION INTERRUPTION/HIGH IMPACT SITES PROGRAM.

A. The long duration interruption/high impact sites ("LDI/HIS") program consists of adding redundant circuits to communities or high impact sites currently served by only one circuit. Redundant circuits do indeed provide a back-up source of power should the primary source fail and can reduce the duration of interruptions. My

[55] DEC Response to NCJC Data Request 5-32, attached as Alvarez Exhibit 16.

concerns relate to the value Duke Energy placed in its benefit projections on outage durations shortened through back-up power.

Similar to other GIP programs, Duke Energy projects that 99% of the reliability benefits from the LDI/HIS program will accrue to C&I ratepayers. As I will describe later in this testimony, I believe the economic benefits Duke Energy assigns to reliability improvements for all commercial and industrial ratepayers to be excessive. However, since the focus of the LDI/HIS program is long-duration interruptions, the economic benefit Duke Energy assigned to avoidance of lengthy outages is particularly critical to the calculation of the LDI/HIS program benefits.

In general, Duke Energy's estimates of the value of reliability improvements (i.e., "$ per event") come from secondary research conducted by the U.S. Department of Energy in 2009. This research did not address service outages longer than 8 hours in duration. In 2013, the values were updated for two more recent surveys of small numbers of C&I ratepayers, only one of which addressed outages as long as 16 hours. To estimate the benefits of lengthy (defined by Duke Energy as 96 hours) outages avoided, Duke Energy simply extrapolated the difference between the cost of an 8-hour duration and the cost of a 16-hour duration to 96 hours. This overstates benefits in two ways. First, the 16-hour cost estimate is questionable due to a small sample size. Second, such extrapolation is inappropriate. The authors specifically advise against using the results of their research to estimate the costs to ratepayers of longer duration outages, stating that the study "focuses on the direct costs that ratepayers experience as a result of relative short power interruptions of up to 24 hours at most."[56] In the 2009 research data, it became apparent that as the length of an outage grows longer, the costs ratepayers incur per hour of outage fall. This is because over longer outages, businesses implement contingency plans. Table 3 below, based on the 2009 research data, illustrates this dynamic.[57]

Table 3: Cost per Minute of Outage for Various Durations, C&I Customers

	Under 30 Minutes	1 hour	4 hours	8 hours
Medium & Large C&I	$508/minute	$297/minute	$164/minute	$175/minute
Small C&I	$17/minute	$11/minute	$8/minute	$10/minute

Though it is clear from the 2009 research that the impact per minute falls as outage duration grows, Duke Energy's extrapolation of the 2013 research findings to 96 hours does not take this fact into account.

Q. DO YOU HAVE OTHER CONCERNS REGARDING LDI/HIS PROGRAM BENEFIT OVERSTATEMENTS?

A. Yes. I also believe the reliability improvement estimates to be overstated. For example, while the average historical duration of outages during major event days averaged 16-21 hours for the recent 10-year period Duke Energy analyzed,[58]

[56] Sullivan M, Schellenberg J, and Blundell M. Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Values for LBNL 2009 secondary research updated in 2013. January, 2015. P. 48.

[57] Sullivan M, Mercurio M, and Schellenberg J. Estimated Value of Service Reliability for Electric Utility Customers in the United States. Secondary research completed by LBNL for the US DOE. June, 2009. Page xii.

[58] Multiple workbooks from Oliver Exh. 7, including LDI_DEC-DEP_NC_2019_Consolidated_vF 5-10-19.xlsx; LDI_DEC-

reliability improvements appear to be based in part on reductions in outage durations of 96 hours. Further, reliability improvements are based on "ballpark" percentages of duration improvement for each of the 131 projects identified in the LDI/HIS program without any documentation or support. More than 90% of these "ballpark" duration improvements were estimated at 50%, 80%, 90%, or 95%; less than 10% of LDI/HIS projects were estimated to improve outage durations by 33% or less.[59]

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED ECONOMIC BENEFIT ESTIMATES IN THE TRANSFORMER BANK REPLACEMENT PROGRAM.

A. Unlike most other GIP programs, for which benefits stem almost entirely from reliability improvements, the benefits of the transformer bank replacement program consist of about 50% reliability benefits and 50% avoided asset replacement benefits. Both are overstated. For example, DEP reliability benefits are based on an estimate that 45 of the 101 transformers to be replaced would fail between now and 2034.[60] This projected 45% failure rate is extremely high given DEP's historical average annual substation transformer failure rate of 0.8% (8 in 1,000 likelihood per year) over the last 5 years.[61]

DEP_NC_2020_Consolidated_vF_rev1 7-9-19.xlsx; LDI_DEC-DEP_NC_2021_Consolidated_vF_rev1 7-9-19.xlsx; and LDI_DEC-DEP_NC_2022_Consolidated_vF_rev1 7-9-19.xlsx; tab "Project-Outage-Pastedata"; average of column "MED 10-year CMI" divided by average of column "MED 10year CI".

[59] Ibid, column "Estimated % decrease in event duration".

[60] Oliver Direct, Ex. 7, workbook "Trans_Transformer Bank_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx', tab "Bank Replacement Data – DEP" (45 transformers) and tab "Bank Replacement Program – DEP" (101 transformers).

[61] DEP Response to NCJC Data Request 5-18, included as Alvarez Exhibit 17.

The extremely high projected failure rate relative to historical actuals also overstates asset replacement benefits. Duke Energy should not count as benefits the cost of avoided replacement of assets that would not likely have failed. Finally, there is no value in prospective replacement of transformers, as there is no need to guess which transformers might fail. As Witness Stephens testifies, it is standard industry practice to test substation transformer oil to identify for replacement those transformers with a relatively high likelihood of failure.[62]

Q. DESCRIBE THE ASSUMPTIONS LEADING TO OVERSTATED RELIABILITY IMPROVEMENT ESTIMATES IN THE OIL-FILLED BREAKER REPLACEMENT PROGRAM.

A. Like transformers, oil-filled circuit breakers can be tested to identify those that should be replaced. As Witness Stephens testifies, this is standard practice for circuit breakers. So, as with transformers, there is no reliability improvement or avoided asset replacement value associated with prospective replacement of oil-filled breakers. Instead, breakers should simply be tested and replaced as indicated by test results. To illustrate the benefit overstatement, DEP reports that the historical average annual failure rate for all types of transmission-class breakers over the last five years is just 0.0638% (6.38 in 10,000 likelihood per year).[63] Yet Duke Energy estimates that of the 370 DEP oil-filled circuit breakers proposed for prospective replacement, 456, or 123%, would have failed by 2032.[64]

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[62] Direct testimony of Dennis Stephens on behalf of NCJC et al., p. 34 at line 18.

[63] DEP Response to NCJC Data Request 5-16, attached as Alvarez Exhibit 6.

[64] Oliver Direct Exh. 7 workbook Trans_Oil Breaker_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tabs “Oil Breaker Program – DEP” (370 breakers) and “Oil Breaker Data – DEP” (456 breakers).

B. Systemic Assumptions Leading to Overstatements of Benefits

Q. WHAT ARE YOUR CONCERNS WITH THE ESTIMATES OF ECONOMIC IMPACT PER CI OR CMI BY RATE CLASS THAT DUKE ENERGY USES TO TRANSLATE RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS?

A. I have many. Of the economic benefits from reliability improvements that Duke Energy projects, 97% are projected to accrue to C&I ratepayers, making the estimates of economic impact per CI or CMI for these ratepayers particularly critical to the GIP benefit calculations overall. My concerns about these estimates, which are likely to lead to overstated economic benefits for nonresidential ratepayers and the GIP overall, include:

- The estimates are based on a limited number of surveys of manufacturing and retail ratepayers only, conducted decades ago;
- The definition of a "large" C&I ratepayer is very small, increasing the large C&I ratepayer count to which avoided cost estimates are multiplied; and
- There is no consistency in how survey respondents took back-up generation and uninterruptible power supplies into account when completing surveys.

Q. PLEASE EXPLAIN HOW SURVEY ADMINISTRATION OVERSTATES ECONOMIC BENEFIT ESTIMATES.

A. The survey data, from a 2009 secondary research project, cannot be used in the manner Duke Energy is using it to translate reliability improvements into economic benefits.[65] It consisted of review and analysis of the results of just 34 surveys of

[65] Sullivan M, Mercurio M, and Schellenberg J. Estimated Value of Service Reliability for Electric Utility Customers in the United States. Secondary research completed by LBNL for the US DOE. June, 2009. Page xii.

commercial and industrial ratepayers conducted by only 10 utilities from 1989 to 2005. The survey data is old, and also suffers from geographic bias, with no surveys conducted by utilities in Mid-Atlantic or Northeastern states. In addition, only manufacturing and retail ratepayers were surveyed. All other types of C&I ratepayers—service businesses, healthcare facilities, agricultural businesses, non-profit facilities, government facilities—were excluded. Finally, the size of the total sample set is extremely small. By my estimate, the economic impacts of service outages on C&I ratepayers is almost certain to be based on less than 10,000 manufacturing and retail C&I ratepayers surveyed from 1989 to 2005. Though the economic impacts were updated in 2013 through the addition of another 20,000 observations – likely only an additional 4-5,000 C&I ratepayer surveys – this effort does not fix the significant survey administration flaws.

In sum, the data is old, geographically biased, and biased towards manufacturing and retail businesses, which likely have the highest service interruption costs of C&I industry segments. I do not believe the Commission should rely upon C&I economic benefit estimates based on limited C&I ratepayer survey data.

Q. PLEASE EXPLAIN HOW SURVEY INCONSISTENCIES REGARDING BACK-UP GENERATION AND UNINTERRUPTIBLE POWER SUPPLIES OVERSTATE ECONOMIC BENEFIT ESTIMATES.

A. The authors of the DOE secondary research admit that surveys used to collect outage cost data did not address the availability of back-up generation and uninterruptible power supply ("UPS") systems in a consistent way.[66] A failure to consider the impact-reducing effects of back-up generation and UPS systems when estimating the costs of service outages to C&I ratepayers clearly results in overstated benefit estimates, because most facilities now have such systems. A more recent, unbiased survey of C&I ratepayers, across 49 different facility types, indicates that 80% had back-up generation available, 61% had UPS systems available, and 59% had both.[67]

Q. PLEASE EXPLAIN HOW THE DEFINITION OF A "LARGE" C&I RATEPAYER OVERSTATES ECONOMIC BENEFIT ESTIMATES.

A. Another critical flaw in the survey methodology is the breakdown of ratepayers by size. When Duke Energy queried its ratepayer data to quantify the number of "large" C&I ratepayer counts against which to apply the DOE secondary research values per outage, it defined "large" as using 50 MWh or more. Duke Energy applied the highest avoided cost benefit estimate to these "large" customers. Yet in 2018, DEC's average residential ratepayer consumed 13.2 MWh per year.[68] Using such a low MWh threshold to categorize a C&I ratepayer as "large" results in higher ratepayer counts, to which overstated "value per outage" estimates are then applied, which in turn overstates the economic benefits Duke Energy will actually deliver to C&I ratepayers. To illustrate, Duke Energy multiplies each momentary

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[66] Ibid. Page 97.

[67] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

[68] US Energy Information Administration. Customer count and sales data by rate class reported by DEC and DEP on Form 861.

(less than one minute) outage it claims to reduce for a "large" C&I ratepayer in 2019 by over $15,000. It is difficult to believe that a C&I ratepayer with usage roughly equivalent to four residential ratepayers can incur such a cost from a momentary outage, particularly when research indicates that 66% of US manufacturing facilities and 49% of retail stores employ on-site UPS systems.[69]

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE MANNER IN WHICH DUKE ENERGY IS USING THE ECONOMIC IMPACT PER CI AND CMI TO ESTIMATE BENEFITS?

A. Yes. The surveys and secondary research the DOE completed were designed to estimate the economic impact *to each individual ratepayer* of service outages of various durations. It is inappropriate to aggregate the impact of individual C&I service outage impacts into a total C&I ratepayer impact estimate, without considering countervailing beneficial impacts to other C&I ratepayers, as this leads to exaggerated overall avoided cost benefit estimates. Consider several scenarios that are likely common in the event of a service outage:

- A residential customer, faced with no electricity for cooking and air conditioning, decides to go out to dinner, or to shopping mall, benefitting some businesses.
- A motorist in need of gasoline bypasses a gas station without power in favor of a gas station with power.

[69] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

- A retail shop experiencing a momentary outage continues to ring up sales and process credit card transactions using the UPS systems attached to each register.
- A farmer who uses electric pumps to irrigate his or her fields simply elects to irrigate later in the day once power is restored, or to double irrigation the next day.

In each of these scenarios, the aggregation of individual C&I ratepayer impacts to estimate total C&I impacts leads to an exaggeration of overall costs incurred by C&I ratepayers. In the first scenario, the service outage results in an economic benefit for some C&I ratepayers. In the second scenario, the economic cost to one gas station represents an economic benefit to a second gas station. In the third scenario there is virtually zero economic C&I ratepayer cost (limited to ratepayers who approach the store during the 30-seconds in which the power is out, and decide not to shop), and in the fourth scenario there is zero C&I ratepayer economic cost. Yet the aggregation and application of the individual C&I impacts per CI or CMI consider none of the offsetting impacts of these scenarios.

Q. DO YOU HAVE ANY OTHER EVIDENCE TO BACK UP YOUR ASSERTION THAT THE APPROACH USED TO TRANSLATE RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS RESULTS IN OVERSTATED ECONOMIC BENEFITS?

A. Yes. Duke Energy claims that the benefits of its TUG program are driven largely by a reduction in momentary outages for C&I ratepayers located “upstream” of an outage in a backyard line. As Witness Stephens describes in his testimony, these momentary outages can be eliminated through other means at almost no cost. But for the sake of argument, let us assume that TUG is used to reduce momentary outages. In discovery, I asked for the industry classification codes of the C&I ratepayers associated with a specific undergrounding project to serve as an illustrative example. In this particular neighborhood there were only six "large" C&I ratepayers for which the project was projected to reduce momentary outages. With some additional research, I determined these six ratepayers to be:

- A large office complex with two 14-story towers;
- A smaller office building (three stories);
- A chain hotel;
- A restaurant;
- A commercial school (for example, a massage therapy or cosmetology school); and
- An unspecified retail establishment.

Note that none of these ratepayers are manufacturers, and only two are retail establishments. In the details provided in the TUG program cost-benefit analysis, it appears that upstream momentary outages for these facilities were 2.9 per year.[70] Assuming the "post-undergrounding" performance will be DEP's 2018 average, or 1.35 (SAIFI),[71] the improvement due to undergrounding will result in less than two

[70] Oliver Exh. 7, workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx", tab "Area Data - Condensed", line "Annual Momentary Events Caused by Neighborhood Events (10 year average)."

[71] NCUC Docket No. E-100 Sub 138A. *DEC and DEP Quarterly Service Reliability Report (Q4, 2019).* Jan 29, 2020. p. 1.

fewer momentary outages per year, on average, for these six ratepayers. Recall that momentary outages are defined as less than a minute in duration. Consider also that UPS systems, which are sufficient to power through a momentary outage without incident, are available at 72% of stand-alone U.S. office buildings and 65% of U.S. hotels.[72] Yet Duke Energy's estimated annual value for momentary service interruption reductions for just these six C&I ratepayers amounted to $303,000 in 2025, growing to $561,000 in 2050, for a primary, present value benefit valuation of $3.6 million.[73] It is hard to imagine that these six C&I ratepayers would be willing to pay (i.e., to "value") pro-rata shares of $3.6 million to secure a reduction of less than 2 momentary outages per year. If these ratepayers don't already have them, UPS systems would be much less costly to install, not to mention more effective (as they reduce the momentary outages to zero, not to the Duke Energy average of one per year).

Q. DO YOU HAVE ANY QUANTITATIVE DATA TO BACK UP YOUR ASSERTION THAT THE AGGREGATION OF INDIVIDUAL SERVICE OUTAGE IMPACTS OVERSTATES THE OVERALL SERVICE OUTAGE IMPACT?

A. Yes. The US DOE has developed an online tool, the Interruption Cost Estimator, to estimate the value of improvements in service interruption duration SAIDI and service interruption frequency SAIFI. The tool uses the same (overstated) CI and CMI reduction valuations provided in the previously-cited LBNL secondary

[72] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory. April, 2016. Page 13.

[73] Oliver Exh. 7 workbook TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx, tab "Mountainbrook", line 46 (Large CI ratepayer Momentary Interruption Cost avoided).

research that Duke Energy uses to translate reliability improvements into economic benefits in its program cost-benefit analyses. In discovery, I asked Duke Energy to estimate the system-wide SAIDI and SAIFI impacts of the GIP.[74] I input these SAIDI and SAIFI improvement estimates, along with the other data inputs listed below, into the Interruption Cost Estimator.

Table 4: DEC and DEP Inputs to the US DOE's Interruption Cost Estimator/Value of Reliability Improvements Tool

	Duke Energy Carolinas	Duke Energy Progress
State:	North Carolina	North Carolina
Non-Res Customer Count	285,618	208,383
Res Customer Count	1,719,715	1,203,508
Start Year:	2020	2020
Expected Asset Lifetime	30 years	30 years
Inflation rate	2.5%	2.5%
Discount Rate	6.8%	6.8%
SAIFI Before Improvement	1.09	1.35
SAIFI After Improvement	0.93	0.99
SAIDI Before Improvement	205	166
SAIDI After Improvement	177	111

The Interruption Cost Estimator indicated that the present value of the SAIDI and SAIFI improvements in DEC would be $1.957 billion, and the present value of the SAIDI and SAIFI improvements in DEP would be $2.835 billion. The combined benefit from the tool, $4.792 billion, is 40.9% less than the $8.106 billion in primary, present value benefits related to reliability Duke Energy projects from the GIP. In addition, recall that this lowered benefit estimate still suffers from the use of overstated economic values ($ per event) for C&I customers I described earlier.

[74] DEC Response to NCJC Data Request 5-10; and DEP Response to NCJC Data Request 2-7, attached as Alvarez Exhibit 18.

Q. ARE THERE OTHER SYSTEMIC BENEFIT OVERSTATEMENTS OF WHICH THE COMMISSION SHOULD BE AWARE?

A. Yes. In several cost-benefit analyses, Duke Energy claims that spending on prospective replacement of an asset today results in a benefit to ratepayers. The rationale is that by spending $10 today, ratepayers can avoid spending $10 tomorrow, so the $10 that won't have to be spent tomorrow constitutes a benefit. In other words, Duke Energy is claiming that spending capital this year, and raising rates now, when it could have waited to spend that capital for five or ten years, is a ratepayer benefit. This makes no sense.

GIP programs in which future avoided costs are used to justify the advancement of capital spending without documented need to replace assets include TUG; transformer bank replacement; and oil breaker replacement. Duke Energy credits spending capital on these programs today with the avoidance of over $146 million in capital spent tomorrow.[75] The capital spending is not avoided, however; it is accelerated. Any claim of a "benefit" from spending capital earlier than necessary is sheer fantasy.

C. Dubious Secondary Economic Benefits from the GIP as Estimated by the IMPLAN model

Q. DO YOU HAVE OTHER INFORMATION WHICH INDICATES THAT DUKE ENERGY'S GIP BENEFITS ARE INFLATED BY BILLIONS OF DOLLARS?

A. Yes. The primary GIP benefit estimates I have critiqued so far suffer from a compounding effect. That is, reliability improvement estimates are *multiplied* by

[75] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7. Attached as Alvarez Exhibit 10.

estimates of economic benefit per CI or CMI to estimate total economic benefits. During such multiplications, benefit overstatements are multiplied too. When somewhat overstated improvement estimates are multiplied by somewhat overstated economic benefits per unit of improvement, a dramatically overstated estimate of total economic benefit – the product of two overstated benefit estimates – results. For example, assume a reliability improvement estimate of 5 units is overstated by 20%, meaning that the actual reliability improvement was only 4 units. Assume that the economic benefit associated with each unit of reliability improvement, say $10, is also overstated by 20%, meaning that the actual economic benefit associated with each unit of reliability improvement is only $8. While a total benefit estimate using the overstated values would be $50 (5 units x $10/unit), the total benefit estimate using the actual values would be $32 (4 units x $8/unit). Here you can see the compounding problem, as two 20% overstatements, when multiplied, deliver a result which is overstated by more than 56% ($50 divided by $32).

Q. IS THIS THE TOTAL EXTENT OF THE COMPOUNDING PROBLEM IN DUKE ENERGY'S ESTIMATES OF GIP BENEFITS?

A. No. There is no question in my mind that Duke Energy's estimate of $9.2 billion in primary benefits, in present value terms, is dramatically overstated as a result of overstated reliability improvement, overstated estimates of the economic benefit per unit of reliability improvement, and the compounding effect. But Duke Energy then goes one step further. In an attempt to estimate the secondary benefits of its GIP to the North Carolina economy, DEC uses the dramatically overstated primary GIP ratepayer benefits as inputs into the IMPLAN software. Though the IMPLAN software suffers from other deficiencies, one deficiency is that it multiplies the dramatically overstated primary GIP benefits, which are themselves the product of compounded overstatements in reliability improvement and "value per avoided event" estimates, yet again.

Q. CAN YOU EXPLAIN THE DIFFERENCE BETWEEN PRIMARY AND SECONDARY BENEFITS OF THE GIP?

A. As explained by Duke Energy Witness Oliver, "Primary benefits consist of value that is directly captured by the Company and by customers."[76] He provides examples such as reductions in O&M spending by the Company and the costs ratepayers avoid when service interruptions are avoided, such as lost sales, lost product, and lost wages. He describes secondary benefits as "indirect value of the plan to third parties".[77] Though Witness Oliver does not say so directly, my understanding of the IMPLAN software leads me to think of these as "ripple effects" throughout the economy. For example, when a retail establishment loses a sale during an outage, the sales of companies that provide products and services to the establishment fall too. Or, when an employee is not sent home due to a power outage that a GIP investment avoided, that employee might spend the wages not lost on dining out, therefore benefitting a restaurant. Had the employee lost wages due to a service interruption, he or she might have economized, and cooked a meal at home instead.

Q. AREN'T THOSE LEGITIMATE BENEFITS OF RELIABILITY IMPROVEMENTS?

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[76] Oliver Direct, Page 41 at 8.

[77] Ibid, Page 42 at 2.

A. Yes, they are, and Duke Energy uses the IMPLAN software to estimate these secondary benefits. The IMPLAN software was developed to estimate the "ripple effects" throughout an economy from a specific economic activity. For example, IMPLAN can be used to estimate the secondary impacts of increases in hiring at a manufacturing plant, or the contributions of a particular industry, such as tourism or solar power, on a state's economy. However, as I mentioned before, Duke Energy uses dramatically overstated primary economic benefits from reliability improvements as inputs into IMPLAN. Obviously, dramatically overstated IMPLAN inputs lead to dramatically overstated IMPLAN secondary benefit outputs. As great as this deficiency is, however, Duke Energy's secondary benefit estimates suffer from a much greater failing. That is, in evaluating the costs and benefits of its GIP, Duke Energy makes no attempt to estimate, let alone consider, the detrimental impacts on the North Carolina economy of the significant rate increases the GIP will generate.

Q. SO, DUKE ENERGY ESTIMATES THE SECONDARY BENEFITS OF RELIABILITY IMPROVEMENTS TO THE NORTH CAROLINA ECONOMY, BUT DOES NOT ESTIMATE THE DETRIMENTAL IMPACT OF HIGHER RATES TO THE NORTH CAROLINA ECONOMY?

A. That is correct. It is extremely misleading to incorporate secondary benefits in a cost-benefit analysis without also incorporating detrimental secondary impacts.

Q. WHAT ARE THE IMPACTS OF ELECTRIC RATE INCREASES ON THE NORTH CAROLINA ECONOMY?

A. The need for electricity is so universal and so ubiquitous that an increase in electric rates has an economic impact similar to a tax increase. In fact, one could conclude that electric rate increases have a greater impact than tax increases because taxes are more selective. (Only property owners pay property taxes, and only income earners pay income taxes, while almost all people and organizations, including renters, non-profit organizations, and government agencies, buy electricity.)

Electric rate increases manifest in multiple ways throughout a state's economy. Retailers must raise prices; governments may raise taxes or reduce services; businesses may look elsewhere for expansion; some business shift production to out-of-state or overseas facilities; and some businesses become more likely to close. It is certainly plausible, if not likely, that the negative impact of a 3.8% rate increase (5.0% not including fuel costs) offsets or even exceeds the secondary economic benefits Duke Energy estimates from its GIP. Based on the fact that Duke Energy's secondary benefits are based on dramatically overstated primary benefits (via inputs to the IMPLAN software), and due to the fact that the negative impact of electric rate increases likely exceed any secondary impacts of reliability benefits, I recommend the Commission disregard Duke Energy's secondary benefit estimates entirely.

Q. SINCE YOU SUBMITTED TESTIMONY ON DUKE ENERGY'S GRID IMPROVEMENT PLAN IN THE DEC RATE CASE, DOCKET NO. E-7, SUB 1214, ECONOMIC CONDITIONS IN THE UNITED STATES, AND IN NORTH CAROLINA, HAVE DETERIORATED CONSIDERABLY DUE TO THE COVID-19 PANDEMIC. DO THESE DETERIORATING ECONOMIC CONDITIONS IMPACT YOUR CONCLUSIONS AND RECOMMENDATIONS WITH REGARD TO THE GIP?

A. Yes and no. Making cost-ineffective investments in the grid is unwise regardless of economic conditions. As I'll testify in the next section of testimony on distribution planning and capital budgeting, the Commission should consider rate increases a finite resource, and the capital investments driving those increases should be prioritized by customers and stakeholders, not by Duke Energy. These recommendations are relevant regardless of economic conditions. Both Mr. Stephens and I provide extensive evidence that the risk GIP costs will exceed GIP benefits is high. Even if the impending recession failed to materialize, our recommendations that the Commission should reject the GIP would stand.

As the Commission is aware, the COVID-19 pandemic is already disrupting the lives of North Carolinians, including DEP's customers. An economic recession of unrivaled speed and breadth is underway, and is likely to deepen, causing hardship to ratepayers of all classes and impairing the economy's ability to absorb rate increases. The Commission has already recognized the pandemic's "potentially devastating health and financial impacts on [utility] customers' lives" in its order suspending utility disconnections for nonpayment.[78] Even for customers who are able to pay their bills, however, the emerging economic crisis virtually ensures that both residential and non-residential customers will assign a higher priority to electric affordability. It is also possible, if not likely, that pandemic- or recession-related supply chain disruptions will lead to GIP project cost increases, for which customers bear all risk. This is therefore not the time to make high-risk, cost-ineffective investments that will increase rates, and I hope the Commission takes these customer priorities in light of changing economic conditions into account when rendering a decision on the GIP.

[78] Order Suspending Utility Disconnections For Non-Payment, Allowing Reconnection, and Waiving Certain Fees, Docket No. M-100, Sub 158 (March 19, 2020).

Q. YOU HAVE TESTIFIED THAT DUKE ENERGY'S GIP UNDERSTATES RATEPAYER COSTS BY BILLIONS OF DOLLARS, AND OVERSTATES RATEPAYER BENEFITS BY BILLIONS OF DOLLARS. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE BENEFITS AND COSTS OF DUKE ENERGY'S GIP?

A. Based on the detailed review of GIP programs, costs, and benefits Witness Stephens and I have conducted, I conclude that the GIP is *at best* a break-even proposition for Duke Energy ratepayers overall. In addition, given that 87% of projected GIP benefits stem from reliability improvements, and that 97% of these benefits are projected to accrue to C&I ratepayers,[79] I conclude that the GIP costs dramatically exceed GIP program benefits for residential ratepayers.

Q. DO YOU HAVE ANY ADDITIONAL SUPPORT FOR YOUR CONCLUSION THAT THE GIP COSTS DRAMATICALLY EXCEED GIP PROGRAM BENEFITS FOR RESIDENTIAL RATEPAYERS?

A. According to DEP, despite the paltry percentage of reliability improvements that will accrue to residential ratepayers, residential customers will likely be allocated about 59.2% of GIP costs.[80] Assuming, for the sake of argument, that Duke Energy's estimate of primary, present-value GIP benefits ($9.2 billion) are not overstated, I calculate that residential ratepayers will pay at least $10.44 for every $1 in benefits they receive:

[79] My analysis of multiple, program-specific cost-benefit analyses provided in Oliver Direct, Ex. 7. Attached as Alvarez Exhibit 10.

[80] Pirro Direct, Ex. 4, page 2. "Calculations for Rate Design"" ($284,127) (RES) divided by "Total Retail"$479,578).

Table 5: Calculation of residential ratepayer cost per dollar of residential GIP benefit

Economic benefits from reliability:	$8.106 billion
Residential ratepayer share of reliability benefits (2.6%):	$213 million
Present value of revenue requirements:	$3.447 billion
Residential ratepayer share of revenue requirement (59.2%)	$2.041 billion
Residential ratepayer cost per dollar of reliability benefits ($1.817 billion in costs divided by $213 million in benefits):	$10.44

Q. DOES THIS PROMPT ANY CONCERNS ABOUT INEQUITIES OF THE GIP AS PROPOSED?

A. Yes, and not just between residential and C&I ratepayers. If the GIP is approved as proposed, my revenue requirement estimate indicates Duke Energy shareholders will likely earn about $2.6 billion in return on equity over 30 years ($1.2 billion in present value terms). Yet if Duke Energy spends more on the GIP than promised (which, as indicated in my testimony on costs, is a number that has yet to be determined), ratepayers bear the risk. If Duke Energy delivers fewer benefits than projected, ratepayers bear the risk. The loose definition of costs ratepayers will have to pay, lack of Duke Energy accountability, and inequities in risk allocation all seem unjust and unreasonable to me. To address these GIP deficiencies, I believe one solution holds promise: the development of a transparent, stakeholder-engaged approach to distribution planning and capital budgeting process for future use in North Carolina.

VI. The Stakeholder Engagement DEC/DEP Conducted Was Superficial and Inadequate.

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony I will address the critical issues of transparency and stakeholder engagement in distribution planning and capital budgeting. I will begin with a quick review of the stakeholder engagement Duke Energy conducted in the development of its GIP, highlighting some deficiencies that have yet to be corrected. I will then present a step-by-step distribution planning and capital budgeting process that features true, transparent stakeholder engagement, and the development of stakeholder competencies over time. The purpose of this portion of my testimony is to compare the stakeholder engagement that has been conducted to date to the type of long-term, ongoing, holistic distribution planning and capital budgeting process that is possible, and which other jurisdictions are considering. Finally, I will describe the potential benefits that ratepayers could expect from the proposed process.

Q. WHAT IS YOUR IMPRESSION OF THE STAKEHOLDER ENGAGEMENT DUKE ENERGY CONDUCTED IN THE DEVELOPMENT OF THE GIP?

A. As I understand it, the stakeholder engagement process consisted of three phases, each marked by a workshop. The first phase/workshop consisted of Duke Energy's presentation of "Megatrends," and presented high-level information on the programs that would later be incorporated into the GIP. In phase two, Duke Energy presented its current GIP to stakeholders in a workshop. Although the GIP reflected changes based on stakeholders' critique of Power Forward, it was made clear that there would be no further changes to the GIP based on stakeholder feedback. In phase three, Duke Energy responded to stakeholder requests for more information through another workshop and some webinars focused on individual programs, costs, and benefit estimates. I perceive these efforts as Duke Energy's attempt to satisfy the Commission's request for more stakeholder engagement in grid modernization plan development as specified in the Commission's last rate case order.

Q. DO YOU BELIEVE THAT STAKEHOLDER ENGAGEMENT PROCESS WAS ADEQUATE?

A. As they say, "the proof is in the pudding." Judging by the GIP filed in this case, I must conclude that the stakeholder engagement effort did not result in a plan that delivers more value to ratepayers. Of the new programs presented in the GIP, two of the programs (energy storage and electric transportation) were initiated by the Commission, not Duke Energy. Of the remaining six new programs, Witness Stephens's testimony categorizes four of them – transformer replacement, oil-filled breaker replacement, transmission system intelligence, and physical substation security, totaling over $500 million in proposed investment – in the "merits rejection" category. Duke Energy did not even bother to develop cost-benefit analyses for two programs, including distribution automation (expanded) and transmission system intelligence (new). A truly transparent distribution planning and capital budgeting process featuring genuine stakeholder-engagement would have avoided most, if not all, of these deficiencies before the plan was ever presented to the Commission.

Q. WHAT DO YOU BELIEVE DUKE ENERGY'S GIP STAKEHOLDER ENGAGEMENT PROCESS MISSED?

A. In the very first workshop, stakeholders "discussed the need for clear, concise metrics to prioritize grid modernization outcomes, measure the success of proposed programs, and determine the need for revisiting programs post-implementation." The GIP incorporates none of these items and does not hold Duke Energy accountable for GIP costs or benefits. Also in the first workshop, "Participants expressed a wide and diverging range of views on grid investment priorities."[81] It is unclear that these differences were resolved, and whether and to what extent stakeholder priorities were considered in development of the GIP. In the second workshop, stakeholders wanted to know "how much additional DER the grid could support with the plan's improvements."[82] Duke Energy's transmission hardening and resilience program does not increase its grid's capability to accommodate DER by a single kilowatt, although DER accommodation is a critical concern of many stakeholders and ratepayer segments. Finally, despite the obvious stakeholder concern about how the multi-billion-dollar GIP would affect rates, Duke Energy provided no estimated rate impact to stakeholders,[83] and still has not done so. These are clear and unequivocal indictments of the current distribution planning and capital budgeting process. I believe there is a much better way.

Q. WHAT KIND OF TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS DO YOU HAVE IN MIND?

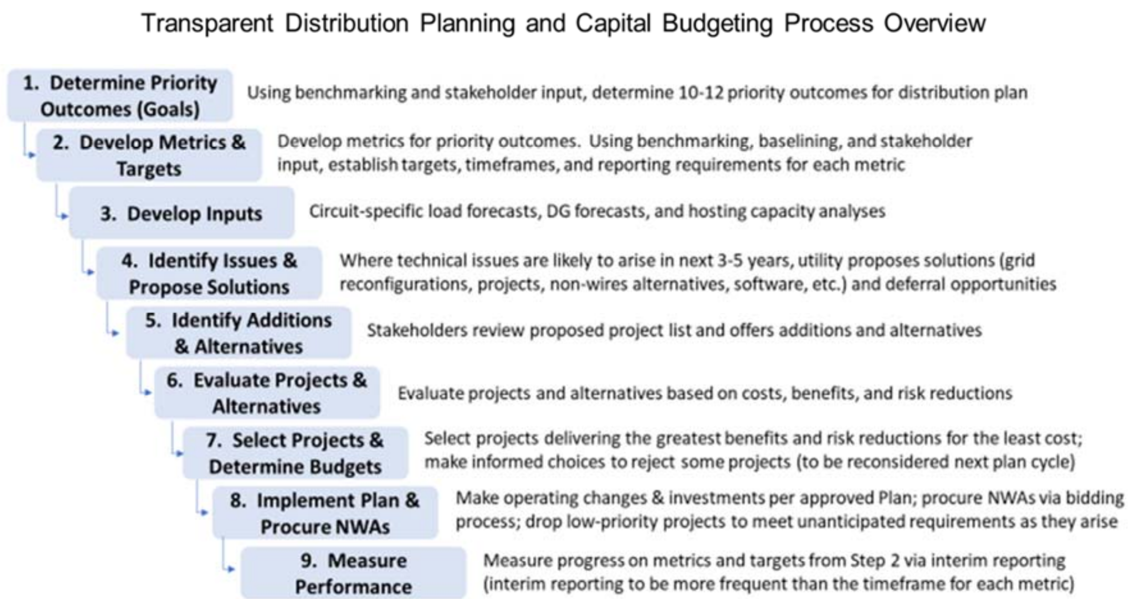
[81] Oliver Direct, Exh. 11, page 5.

[82] Oliver Direct, Exh. 13, page 12.

[83] DEC Response to NCSEA Data Request 2-16, attached as Alvarez Exhibit 19.

A. A full description of such a process at this point in my already lengthy testimony is not possible. However, Figure 3 provides an overview of the steps of a process the Commission might want to consider.

Figure 3: A transparent distribution planning and capital budgeting process for consideration



A process like this could be completed with stakeholder involvement every three to five years. The utility takes the lead on steps (3) develop inputs; (4) identify issues and propose solutions; (8) implement plan and procure non-wires alternatives; and (9) measure performance. All of these steps are familiar to utilities today, with the possible exception of circuit-specific DER forecasts and hosting capacity analyses. But these could easily be fit into utilities' existing distribution planning processes and are already commonplace among California and Hawaii utilities with high DER penetrations. All the other steps are intended to be led by Commission staff and stakeholders, with utility input. All differences are negotiated between stakeholders and the utility. Only issues that cannot be resolved would be brought to the Commission for a decision.

A distribution planning and capital budgeting process like this would resolve all the items missing from the GIP stakeholder engagement process. It incorporates goals, metrics, targets, and performance measurement. It holds the utility accountable for performance, and involves stakeholders early in evaluation of costs, benefits, and risk reductions of optional solutions to technical issues. It forces stakeholders to negotiate and agree upon priorities. It lets all stakeholders know the DER capacity available on various circuits, identifies constraints in advance, and provides mechanisms for resolving those constraints in the context of all other grid performance, safety, security and affordability priorities.

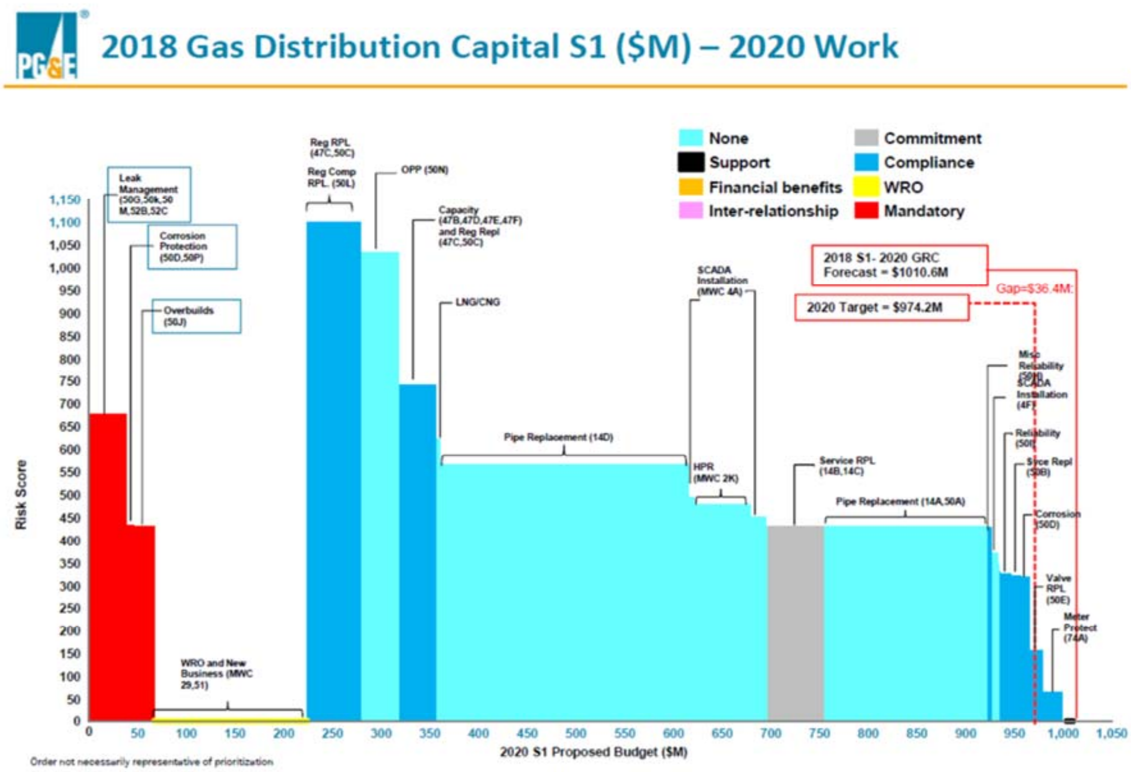
Q. STEP SEVEN APPEARS TO ALLOW STAKEHOLDERS AUTHORITY OVER DISTRIBUTION CAPITAL BUDGETS.

A. Yes, but with utility input, and the notion is not as far-fetched as you might believe. The safety portions of some distribution utility capital budgets are already determined in this manner. Figure 4 depicts the latest evolution of a risk-informed decision support process used by Pacific Gas and Electric's gas distribution planners following the highly publicized San Bruno pipeline explosion in 2010 that killed 8 residents.[84] Each block in the diagram represents a project, with the height of the block indicating the value (in this case, the amount of safety risk reduction) and the length of the block indicating capital cost. By organizing the projects in descending order of value and cost, stakeholders can quickly understand the trade-

[84] California PUC A.18.12.009. PG&E 2020 General Rate Case. Exhibit PGE-3, Gas Distribution Workpapers Supporting Chapters 2-2A. Page WP 2-10. December 13, 2018.

offs associated with various budget levels. Stakeholder questions the diagram can answer include, "If we establish a budget of $750 million, what value will we receive? What reduction in value is associated with a budget reduction to $500 million? What increase in value is associated with a budget increase to $900 million?"

Figure 4: PG&E's gas safety capital budget decision support analysis, 2018.[85]



Q. ARE OTHER JURISDICTIONS CONSIDERING DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESSES LIKE THIS?

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[85] California PUC A.18-12-009. Pacific Gas & Electric General Rate Case. Exhibit PG&E-3 "Gas Distribution Workpapers Supporting Chapters 2-2a". Page WP 2-10. Dec. 12, 2018.

A. Yes. The California Public Utilities Commission has an ongoing docket[86] dedicated to distribution planning process improvement; several of the steps presented above are already a transparent part of distribution planning in that state. Commissions in Michigan[87] and New Hampshire[88] are currently evaluating the process described above (in greater detail, of course) in investigational proceedings. These commissions are recognizing that the rhetorical questions I posed at the beginning of this testimony must be answered, and that investor-owned utilities cannot answer them on their own. These commissions are also recognizing: (1) that grid investment choices have long-term consequences; (2) that the capital amounts involved are enormous; (3) that a state economy's ability to accommodate rate increases is finite; and (4) that investor-owned utility incentives run counter to ratepayer and stakeholder incentives. All this means that grid investments must be very carefully considered and prioritized, and that stakeholder responsibilities in this regard will have to grow.

Q. HOW CAN STAKEHOLDERS GET THE EXPERIENCE THEY WILL NEED TO EFFECTIVELY PARTICIPATE IN A DISTRIBUTION PLANNING PROCESS?

A. Education is a process that happens over time. I am not suggesting that stakeholders are going to become grid engineers. Nor am I suggesting that stakeholders get involved in "business as usual" investment decisions or operations. What they need

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[86] California PUC. Rulemaking R.14-08-013. *Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.*

[87] Michigan PSC Docket U-20147. Five-Year Distribution Investment and Maintenance Plans.

[88] New Hampshire PUC Docket IR 15-296. Investigation into Grid Modernization.

is the opportunity (and desire) to ask questions collegially, rather than in the context of a rate case; an appreciation for basic grid design, equipment, and operating concepts; and an understanding of pros and cons of various decisions and options they will be considering. I know first-hand that this is possible as a result of my working relationship with Witness Stephens over the past couple of years. While he has taught me much about grid design, equipment, and operations, one of the biggest things I've learned is that neither an electrical engineering degree or 35 years' grid planning and operations experiences is needed to understand the pros and cons of optional solutions to technical issues, or to make informed business decisions regarding distribution grids. The most important ingredients are historical operating data, unbiased technical advice, and a willingness to learn.

Q. WHAT DO YOU SEE AS THE ADVANTAGES OF A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS TO RATEPAYERS, THE COMMISSION, UTILITIES, AND STAKEHOLDERS?

A. Ratepayers in general, and state economies more broadly, are the clear focus of such a process. I believe ratepayers will benefit in three ways. First, rate increases will be held to a minimum. Second, ratepayers will secure greater benefits per dollar of rate increase. Third, the distribution grid will be able to accommodate the level of DER capacity ratepayers care to install, as well as the level of electrification they care to pursue, at a reasonable cost to all.

I also believe regulators would see benefits from such a process. Perhaps most importantly, I think the process would improve the state's economy by avoiding low-value rate increases that business and residential ratepayers would otherwise pay, an outcome of great interest to regulators and legislators. Although more difficult to quantify, I think the process would enable regulators to make more informed decisions by providing them with more objective and understandable information about the impacts and trade-offs of various grid investments. Last but perhaps most importantly, such a process would allow regulators to advance state policy objectives at the least possible cost to the North Carolina economy.

Though utilities will likely see the process as a challenge, there are some legitimate silver linings in the process for utilities to consider. Rate increases backed by a distribution plan developed through a transparent, stakeholder-engaged process will be subject to a lower risk of cost disallowances. Another benefit will be a change in the utility's role. Today, utilities make proposals that stakeholders critique. Each stakeholder pursues its own interests, putting utilities in the difficult position of opposing all stakeholders. Using the process, utilities will have an opportunity to become trusted partners and collaborators in a paradigm that respects their expertise and responsibility to assure safety and reliability, while seeking a reasonable return on investment for shareholders. Finally, when utilities are in sole control of distribution investment decisions in conditions of uncertainty, they run the very real risk, if not certainty, of making investments that will turn out to be mistaken with the benefit of hindsight. With stakeholder input, utilities are likely to make better decisions.

Finally, the process offers other stakeholders some of the same benefits recognized above for regulators. For instance, the process offers more transparency to stakeholders, and more objective and understandable information about the impacts and trade-offs of various grid investments. Over time, a stakeholder-engaged distribution planning process will produce stakeholders who are more educated and informed regarding technical distribution issues and distribution technologies, leading to more valuable regulatory processes. This has happened in integrated resource planning over the last few decades in some jurisdictions, and there is no reason the same outcome should not or could not be realized with regard to distribution planning in North Carolina.

VII. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony began with historical evidence from US investor-owned utilities, which indicates that reliability has been deteriorating despite distribution grid investment growth far in excess of peak demand growth in recent years. I then presented evidence that Duke Energy understates the cost of the GIP to ratepayers by billions of dollars, and overstates the benefits of the GIP to ratepayers by billions of dollars. I concluded that the GIP is a break-even proposition *at best* for ratepayers overall, and dramatically negative for residential ratepayers. The GIP is justified almost entirely by reliability improvements for C&I customers, and I estimate residential ratepayers will pay $10.44 for every $1 in GIP benefits (both figures in present value terms). My testimony then compared the stakeholder engagement process Duke Energy conducted in the development of its GIP to a truly transparent and engaging distribution planning and capital budgeting process the Commission may wish to consider in the future.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the GIP deficiencies and improvement opportunities presented, I recommend the Commission reject Duke Energy's GIP, and establish a separate proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. This is consistent with Witness Stephens's primary recommendation. However, should the Commission reject my recommendation, I support Witness Stephens's secondary recommendations, which relate to individual GIP programs rather than complete GIP rejection. I also support all adjustments and conditions described in Witness Stephens's testimony for any GIP programs the Commission approves. Finally, I recommend the Commission reject deferred accounting cost recovery on the basis that it encourages suboptimal capital investment. This is also consistent with Witness Stephens's recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Paul J. Alvarez 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 13th day of April, 2020.

s/ Gudrun Thompson

Gudrun Thompson