PLACE: Held via Videoconference REDACTED

DATE: Thursday, October 1, 2020

TIME: 9:01 A.M. - 12:33 P.M.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

Noteworthy Reporting Services, LLC

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC

for an Accounting Order to Defer Incremental Storm

Damage Expenses Incurred as a Result of Hurricanes

Florence and Michael and Winter Storm Diego

VOLUME 15

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER CLODFELTER: Let's come to order, and we will resume this morning. Before we go back to the Sierra Club, let me just advise the participants that just before we opened this morning, we had a very short the bench conference with the counsel for the Company and Sierra Club with respect to procedures for handling certain information -- confidential information that was inadvertently disclosed during testimony yesterday afternoon.

We will be taking steps to ensure that that information is blocked from general access on the video record and the audio record, and it is appropriately redacted in the written transcript. You should understand that any party who has signed a confidentiality and nondisclosure agreement with the Company will have full access to the unredacted transcript. So we are only blocking public -- general public access through the video record and the audio record, and I think I can say that we've satisfied the Company and the Sierra Club with respect to that confidentiality.

So I just wanted to announce that,

because we did do that a little bit in advance so we can save some time in the actual hearing, itself.

Mr. Robinson, Ms. Lee, you're good to go, right?

MS. LEE: Yes, sir.

COMMISSIONER CLODFELTER: Okay. Fine.

MR. ROBINSON: Yes, sir.

COMMISSIONER CLODFELTER: Great. The case is back with the Sierra Club. And, Ms. Cralle Jones, Ms. Lee, me say, before you call your next witness, that it would not have posted yet this morning, but an order will be posted in the record later today allowing Sierra Club's motion to designate the two exhibits to Ms. Wilson's testimony that were inadvertently left out -- they're referenced in her testimony but were not included in the designation. The motion allowing those -- I believe those are Wilson Exhibits 4 and 5, that motion is being granted, so you may proceed according.

MS. LEE: Thank you, Commissioner Clodfelter.

MR. ROBINSON: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, I'm sorry. Mr. Robinson?

MR. ROBINSON: Yes. Camal Robinson. Commissioner Clodfelter, I have a few procedural items. Let me know if this is an appropriate time to do so.

COMMISSIONER CLODFELTER: Yes, this is good. We are not in the middle of a witness, so I prefer to do it that way anyway. This is good.

MR. ROBINSON: Thank you, sir. First on my list, we too are pleasantly in realization that we are moving at a fast pace. I will knock on wood not to jinx it, and that the latest version of the witness order, including a witness order and cross times, was provided a couple of weeks ago. The Company has prepared a version of the witness order that includes the parties' cross times under the assumption that all stipulated live testimony and cross exhibits from the DEC case will be moved into the record in the DEP case.

We are prepared to file that updated version of the witness list this morning if that pleases the Commission.

COMMISSIONER CLODFELTER: Mr. Robinson,

I think that would be useful, as I think it's the one that I received yesterday; is that correct?

MR. ROBINSON: Yes. There will be some additional revisions to that.

COMMISSIONER CLODFELTER: There will be additional revisions. I think it would be appropriate to go ahead and file and circulate that, because depending on how long on Ms. Wilson testifies, we may be into your rebuttal case very shortly. Well, excuse me, we've got the Public Staff to hassle with a little bit here. We have to wrestle with them a little.

MS. DOWNEY: Okay there.

COMMISSIONER CLODFELTER: All right.

MR. ROBINSON: Yes, sir. Just a few others, and great segue in terms of the reference to the rebuttal case. So as we move closer towards that, Commissioner Clodfelter, we just wanted to alert the Commission and the parties in advance to two changes we intend to make to the presentation of our rebuttal witnesses.

So the first one. After some additional deliberation, we decided we do intend to all Mr. Riley after all. However, so as not to slow things up, we will simply be adding him to the David Doss and John Spanos panel currently scheduled to testify on the rebuttal case. So that's the first.

COMMISSIONER CLODFELTER: Thank you.

MR. ROBINSON: Sure. The second, so for efficiency purposes, we intend to merge Ms. Bednarcik on rebuttal with the Marcia Williams and Jim Wells panel. We provided the parties that list of cross examination for these witnesses advance notice via email this morning. To those parties, the updated witness list and order that we intend to file shortly consolidates the cross times for all three witnesses by combining the revised cross times you had for Ms. Bednarcik on rebuttal with the revised cross times we had for the Wells/Williams pan on rebuttal into one consolidated time per party. That's all I had.

COMMISSIONER CLODFELTER: Ms. Robinson, as I understand it, that -- that panel of Bednarcik, Wells, and Williams will be the last panel offered by the Company; is that correct?

MR. ROBINSON: That's currently correct, Commissioner Clodfelter, provided there's no procedural or just timing issues that arise, but that's correct.

COMMISSIONER CLODFELTER: Understand. That's fine. Anything further?

MS. TOWNSEND: Commission Clodfelter, we would like to -- this is Terry Townsend from the Attorney General's Office. I did inform Mr. Marzo, due to the advanced notice, that I don't agree that this panel of Bednarcik, Wells, and Williams would be more efficient. As we all recall, the panel was a very lengthy -- took a very lengthy amount of time. Adding Bednarcik to it, I don't think would be efficient.

First of all, the remaining questions that I have for Ms. Bednarcik are for Ms. Bednarcik, specifically, based on the fact that she testified regarding her historical knowledge of the environmental issues at all of the sites. Just because the word "groundwater" is used does that mean that that is specifically Mr. Wells' purview. And I believe that anything that dealt with the historical issues that she has reviewed thoroughly, based on her testimony, are appropriate for her.

I believe that, if we get into a panel

where everyone else is a foray of everyone responding, I don't think that will be efficient. We would ask, if they do have the panel, that's fine, but please also have Ms. Bednarcik as a solo witness.

MR. ROBINSON: Commissioner Clodfelter, may I respond to that?

MS. DOWNEY: Commissioner Clodfelter, before he responds, maybe --

COMMISSIONER CLODFELTER: I'm sorry.

MS. DOWNEY: I'm sorry.

COMMISSIONER CLODFELTER: I see you now, thank you. I had to find you on the screen.

MS. DOWNEY: That's okay. I just wanted to respond before Camal jumped in that the -- I mean Mr. Robinson, sorry -- that the Public Staff, likewise, opposes this panel of Bednarcik, Wells, and Williams. We agree with the Attorney General that it does not provide the efficiencies that I think Duke is hoping for. And we would prefer also to cross Ms. Bednarcik separately.

We would typically not oppose a panel, I'm not sure we ever have, but in this instance we would do so.

COMMISSIONER CLODFELTER: All right. Mr. Robinson -- anyone else before we get to Mr. Robinson?

(No response.)

COMMISSIONER CLODFELTER: All right. Mr. Robinson.

MR. ROBINSON: Commissioner Clodfelter, respectfully, we are talking about the Company's rebuttal case here, and it is entitled to present its witnesses in the format it considers the most efficient and capable to sufficiently respond to questions from the intervenors and this Commission. Many of these issues are highly technical, and it's our obligation to ensure that the responses we give to questions are complete and comprehensive.

We believe it's important to this Commission that we this obligation and allow this Commission to receive the information necessary to evaluate the evidence and afford it the weight the Commission deems it's due.

These are the drivers of the Company's decision, and we respectfully request that the Commission give us this latitude.

COMMISSIONER CLODFELTER: All right.

This is not an issue we have to address immediately, so I'm going to suggest and request that, Ms. Townsend, Ms. Downey, and Mr. Robinson, that you spend some of our break time this morning and probably our lunch hour as well caucusing among yourselves on this question and see if there is a path forward that you can mutually agree upon. And we'll bring this back and see what disposition, if any, I need to make of it at a later point. I don't think we'll actually reach that panel before lunch, certainly, and so that should give you at least two opportunities and perhaps even more to discuss that.

So I'm going to encourage you to talk with each other and see if you can work out some acceptable path. All right? Thank you, though, for bringing it to our attention so we're all thinking about it, and that will give other parties a chance to think about whether they have any views that they might want to share, Mr. Robinson, with you on that subject. Okay?

MR. ROBINSON: Yeah.

COMMISSIONER CLODFELTER: Anything further?

MR. QUINN: Commission Clodfelter?

COMMISSIONER CLODFELTER: Yes, Mr. Quinn.

MR. QUINN: Good morning. This is Matt Quinn with NC WARN. If this is an appropriate time, NC WARN sponsored witness William Powers --

COMMISSIONER CLODFELTER: Mr. Quinn, I don't want to cut you off, but let me tell you what I was going to do this morning. And I'm sorry, I apologized, yesterday I did this out of order at Mr. West's request. I think it was so Mr. West could go on and move elsewhere. My intent is -- Ms. Wilson is the last witness for Sierra Club. My intent before we go to the Public Staff's case was to call upon all of the other intervenors, and that would include you and your client, and get in all of the other intervenor testimony moved into the record before we go to the Public Staff. If that's acceptable to you, we'll just -- that way we can keep the Sierra Club witnesses all together; can we do that?

MR. QUINN: Very good. Thank you, Commissioner.

COMMISSIONER CLODFELTER: I'm sorry to

interrupt you, but I was thinking about you and planning for you.

MR. QUINN: Thank you very much.

COMMISSIONER CLODFELTER: You bet.

Okay. Any other procedural issues?

(No response.)

COMMISSIONER CLODFELTER: All right. Then, Ms. Lee, Ms. Cralle Jones, whichever of you is going to take Ms. Wilson.

MS. LEE: Thank you. Good morning again, Commissioner Clodfelter and Commissioners. Sierra Club calls Rachel Wilson.

THE WITNESS: You're on mute, Commissioner.

COMMISSIONER CLODFELTER: I'm sorry. Thank you.

Whereupon,

RACHEL S. WILSON,

having first been duly affirmed, was examined and testified as follows:

COMMISSIONER CLODFELTER: Thank you. Ms. Lee?

MS. LEE: Thank you.

DIRECT EXAMINATION BY MS. LEE:

Q. Good morning, Ms. Wilson.
Could you please state your full name and business address?
A. My name is Rachel Wilson. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.
Q. Thank you. By whom are you employed and in what capacity?
A. I'm a principal associate at Synapse Energy Economics.
Q. On April 13, 2020, did you cause to be prefiled in this docket, direct testimony consisting of 25 pages and three exhibits, some portions of which contain information designated confidential by the Company?
A. Yes, I did.
Q. And your understanding that, due to a clerical error, Exhibits 4 and 5 that are referenced in your direct testimony, were not filed on April 13th, but since been submitted to the Commission and the parties, and that Sierra Club has sought leave to have those exhibits filed in this proceeding?
A. Yes.
Q. Do you have any changes or corrections to

your prefiled direct testimony?
A. No, I don't.
Q. And if I asked you the same questions again here today, would your answers be the same?
A. Yes, they would.
Q. Ms. Wilson, did you prepare a summary of your direct testimony?
A. Yes, I did.
MS. LEE: Commissioner Clodfelter, we ask that Ms. Wilson's prefiled direct testimony consisting of 25 pages, some portions of which contain information designated confidential by the Company, and her summary be moved into the record as if given orally from the stand.
COMMISSIONER CLODFELTER: You've heard the motion. Hearing no objection, the motion will be granted. And, of course, confidentiality will be preserved in the record as designated in the prefiled materials.
(Whereupon, the prefiled direct testimony and testimony summary of Rachel S. Wilson were copied into the record as if given orally from the stand.)

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address, and position.

A My name is Rachel Wilson and I am a Principal Associate with Synapse Energy Economics, Incorporated ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, developers, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct analysis and write testimony and publications that focus on a variety of issues relating to electric utilities, including integrated resource planning, resource adequacy, electric system dispatch, environmental regulations and compliance strategies, and power plant economics.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models, and I have reviewed input and output data for several other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the North Carolina Utilities Commission?

A Yes. I testified before this Commission in Docket No. EMP-105, Sub 0 and Docket No. E-7, Sub 1214.

Q What is the purpose of your testimony in this proceeding?

A The purpose of my testimony is to evaluate the economics of the coal-fired units owned by Duke Energy Progress (DEP or the Company) and assess the prudence of continuing to invest in and operate these units, which include Roxboro Units 1-4 and Mayo Unit 1.

Q Please identify the documents and filings on which you base your opinions.

A My findings rely primarily upon the testimony, exhibits, and discovery responses of DEP and its witnesses. I also rely to a limited extent on certain industry publications.

In addition to my resume, exhibits to this testimony include:

Confidential Exhibit RW-2: Unit historical energy value and costs, 2016-2018

Confidential Exhibit RW-3: Unit forward-looking energy value and costs, 2019-2029

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My primary findings indicate that all of DEP's coal units operated uneconomically for the combined three-year period from 2016 through 2018. I estimate that each of the coal units had a total negative net value of between [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] between 2016 and 2018. Despite these net losses, DEP continues to determine unit retirement dates for its coal fleet based solely on depreciation studies.

My analysis shows that each of DEP's coal units will continue to operate uneconomically in the future. DEP has not provided any economic assessments of the continued operation of its coal-fired units, even as low gas prices and declining costs for renewables have disadvantaged many coal units across the country. Thus, the Company has not demonstrated that continuing to invest in its coal fired units is a prudent decision and provides value to ratepayers.

Q Please summarize your primary recommendations.

A Based on my findings, I offer the following recommendations:

1. I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEP's coal units had negative net value in 2016, 2017, and 2018. Capital spending during this time period should be disallowed until DEP provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made.
2. Similarly, I recommend that the Commission disallow recovery of ongoing operations and maintenance (O&M) expenses at DEP's coal units, given that DEP's coal units are projected to continue to have negative value in the future.
3. I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEP coal units as generating assets, and

require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.

4. I recommend that in future rate cases, DEP be required to demonstrate that its gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. If DEP cannot make such a demonstration, those units should be removed from rate base.

III. DEP'S COAL UNIT PLANS AND PROPOSALS

Q Which DEP generating units are the focus of this testimony?

A This testimony focuses on the economics of DEP's five coal units for which the utility is seeking cost recovery in this case. These include Roxboro Units 1-4 and Mayo Unit 1.

Q What are DEP's plans regarding the future operation of these units?

A Exhibit 1 of the Direct Testimony of John J. Spanos suggests a "probable retirement year" for each of DEP's coal units. According to this document, the probable retirement years are: 2028 for Roxboro Units 1 and 2; 2029 for Roxboro Units 3 and 4; and 2029 for Mayo Unit 1. These retirement dates accelerate the retirements of Roxboro Units 3 and 4 (from 2033) and Mayo Unit 1 (from 2035) from those in DEP's 2019 Integrated Resource Plan (IRP) Update Report.[1] According to Mr. Spanos, in recent years, originally proposed life spans for coal units have been shortened due to unit efficiencies and environmental regulations.[2]

[1] Duke Energy Progress. *2019 Integrated Resource Plan Update Report*. Page 91.

[2] Direct Testimony of John J. Spanos. Page 10, lines 17-18.

Q What is the basis for DEP's assumed coal unit retirement dates?

A DEP bases its retirement dates on the most recent depreciation study approved by the Commission.[3] In the 2019 IRP Update, the retirement dates were based on the depreciation study approved in the 2017 rate case.

In this docket, DEP is seeking approval for the updated retirement dates shown above based on a new depreciation study provided in Spanos Exhibit. The depreciation in that study refers generally to the loss of service value that result from "wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities."[4] The depreciable life span estimates for DEP's coal units specifically considered the following: life spans of similar generating units, unit age, general operating characteristics, major refurbishments, and discussions with management personnel regarding the long-term outlook for the units.[5]

Q Did DEP provide any economic analyses of alternative retirement dates in its 2019 IRP Update or in this rate case?

A No. DEP has not provided any economic analyses of alternative retirement dates for its coal units. DEP was ordered to do such an analysis as part of its 2020 IRP,[6] however, which is expected in September 2020.

Q What is the implication of this lack of analysis?

A The implication of this lack of analysis is that DEP has assumed that it is cost-effective for ratepayers if the utility operates its coal units based solely on their depreciable lives rather than performing an economic assessment. DEP has therefore provided no justification for continuing to invest in its coal units, and thus no basis for asking its customers to pay for capital expenditures associated with continued operation.

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[3] Duke Energy Progress. *2019 Integrated Resource Plan Update Report*. Page 91.

[4] Direct Testimony of John J. Spanos. Page 3, lines 9-14.

[5] Spanos Exhibit 1. Page 40.

[6] North Carolina Utilities Commission. August 27, 2019. *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*.

Q Have recent electricity market trends affected the economics of coal units in the United States?

A Recent market trends have had a negative impact on the general economics of coal units across the country and led to a sizable number of retirements. According to the U.S. Energy Information Administration (EIA), more than 65,000 MW of coal capacity retired between 2007 and 2018.[7] Coal retirements in 2018 alone totaled 12,900 MW.[8] A range of factors have contributed to these retirements, including sustained low gas prices and increased competition from renewables, which can be expected to persist in the future. Competition from gas and renewables has led to decreases in capacity factors at the coal units that have continued to operate.[9]

Q Have other utilities responded to these changes in the electric sector by conducting retirement assessments of their coal units?

A Yes. Economic assessments of existing coal units have become an increasingly common component of utility resource planning. In its 2018 IRP, Northern Indiana Public Service Company (NIPSCO) examined alternative retirement dates for its five existing coal units, concluding that customers would save more than $4 billion by retiring those units in 2023 rather than operating them until 2030.[10] PacifiCorp's 2019 IRP includes a unit-by-unit retirement analysis of alternative retirement dates, years before the end of the units' depreciable lives, for each of

[7] U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=37817.

[8] U.S. EIA. 2019. *Today in energy: More than 60% of electric generating capacity installed in 2018 was fueled by natural gas.* Available at: https://www.eia.gov/todayinenergy/detail.php?id=38632.

[9] U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=37817.

[10] Northern Indiana Public Service Company LLC. 2018. *Integrated Resource Plan*. Available at: https://www nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.

its 22 coal units across its six-state service territory.[11] Georgia Power's 2019 IRP also included a retirement analysis for each of its existing coal units.[12]

Q What are the important characteristics of a rigorous coal unit retirement analysis?

A A rigorous analysis would include all costs and benefits associated with near-term and mid-term retirement dates. The continued operation of each coal unit would be compared to an optimized replacement resource portfolio, rather than a single replacement resource, that can provide all of the services that would be needed by the system in the absence of the retired unit. The cost of replacement resources should be informed by recent all-source requests for proposals (RFPs).

IV. COAL-RELATED COSTS FOR WHICH DEP IS SEEKING RECOVERY

Q What types of coal unit expenses is DEP seeking to recover through this case?

A DEP is seeking to recover three types of expenses associated with its coal-fired units in this case: O&M expenses, ongoing capital expenditures, and previously incurred capital expenditures associated with unit maintenance and environmental projects.

A What is the test year upon which DEP's rate case application is based?

The test period is January 1, 2018 through December 31, 2018.

Q What levels of O&M expense did DEP incur at its coal units in 2018?

A The plant-specific O&M expenses incurred by DEP in 2018 are listed in Table 1. DEP's total 2018 O&M expense at its five coal units totals $107.4 million.

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[11] Utility Dive. 2019. *Pacificorp sees 2 GW coal retirement, $599M savings by 2040 in latest planning scenarios.* Available at: https://www.utilitydive.com/news/pacifcorp-sees-2-gw-coal-retirements-599m-savings-by-2040-in-latest-plann/562670/.

[12] Georgia Power. 2019. *Technical Appendix Volume 2: Unit Retirement Study to 2019 Integrated Resource Plan.* Georgia Public Service Commission Docket No. 42310.

Table 1. DEP coal plant O&M expense, 2018

Cost Description		Mayo		Roxboro
500 - Oper, Supv, and Engr Exp	$	1,821,164	$	4,234,078
502 - Steam Exp	$	4,186,831	$	15,765,522
505 - Electric Exp	$	5,774	$	9,388
506 - Misc Steam Power Exp	$	1,960,801	$	7,816,440
509 – Allowances	$	3,196,586	$	11,145,165
Total Operations	**$**	**11,171,156**	**$**	**38,970,593**
510 - Maintenance Supv and Engr	$	930,053	$	3,441,572
511 - Maintenance of Structures	$	5,813,943	$	3,352,177
512 - Maintenance of Boiler	$	6,796,191	$	24,116,813
513 - Maintenance of Electric Plant	$	626,332	$	2,838,042
514 - Maintenance of Misc Steam Plant	$	4,507,416	$	4,785,804
Total Maintenance	**$**	**18,673,935**	**$**	**38,534,408**
Total Operation & Maintenance	**$**	**29,845,091**	**$**	**77,505,001**

Source: 2019 DEP NC SC 2-1 a-b DEP OM FY18-Nov 19 YTD.xls.

Q What levels of capital expense did DEP incur at its coal units in 2018?

A The plant-specific capital expenses incurred by DEP in 2018 are listed in Confidential Confidential Table 2. DEP's total 2018 capital expense at its five coal units totals [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] This includes expenditures classified by the Company as associated with ash and wastewater compliance under the Coal Combustion Residuals (CCR) rule and the Effluent Limitation Guidelines (ELG), designated as "CCP" in Confidential Confidential Table 2, as well as capital expenditures associated with maintenance and investment.[13]

[13] Synapse sorted Duke's capital expenditures into the CCR/ELG and non-environmental categories based on the "ENT Function" designated in attachment "CONFIDENTIAL 2019 DEP NC SC DR 5-1 2018 Capital.xls".

Confidential Table 2. DEP coal plant capital expense, 2018

Plant	CAPEX Type	2018
Mayo	[redacted]	
Mayo		
Roxboro		
Roxboro		
Grand Total		

Source: CONFIDENTIAL 2019 DEP NC SC DR 5-1 2018 Capital.xls.

Q What levels of capital expense is DEP planning to incur at its coal units in future projections?

A The plant-specific capital expenses planned by DEP for the 10-year period between 2019 and 2029 are listed in Confidential Confidential Table 3.

Confidential Table 3. DEP future coal plant capital expense, $ Million, 2019-2029

Capital Costs (2019$)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Environmental											
Mayo	[redacted]										
Roxboro 1											
Roxboro 2											
Roxboro 3											
Roxboro 4											
Non-Enviro											
Mayo											
Roxboro 1											
Roxboro 2											
Roxboro 3											
Roxboro 4											
Total											

Source: 2019 DEP NC Sierra Club DR 4-3_Capital Spend Details_CONFIDENTIAL.xls.

We might expect that, as units approach their retirement dates, capital expenditures would ramp down over time. Nonetheless, Confidential Table 3 shows non-environmental capital expenditures of more than [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for Roxboro 3 in 2024, for Mayo 1 in 2025, and again for Roxboro 3 in 2028.

V. HISTORICAL ECONOMIC STATUS OF DEP COAL UNITS

Q Did you assess the recent performance of DEP's coal units?

A Yes. Using data provided by DEP, I evaluated the net value of each of DEP's coal units between 2016 and 2018.

Q Please summarize your findings regarding the recent economic performance of DEP's coal units.

A Confidential Confidential Table 4 summarizes the results of my analysis. I find that for each of DEP's coal units, the costs to maintain and operate the unit exceeded the value provided by the unit by a total of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] over the three-year period.

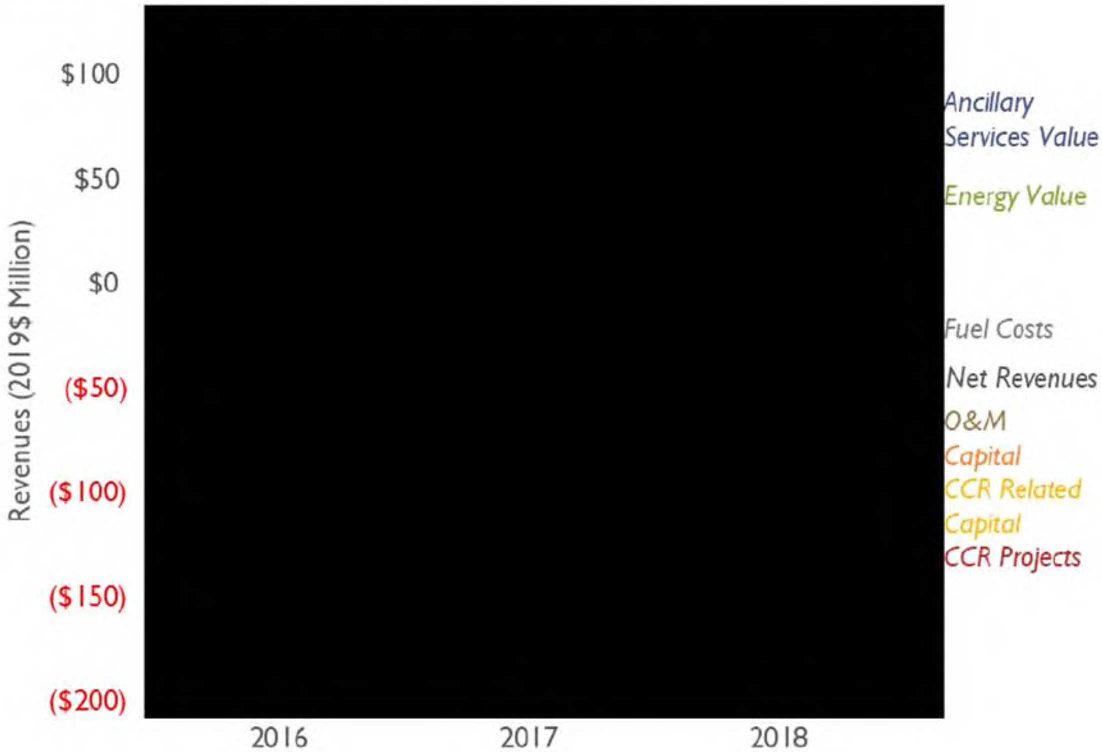
Confidential Table 4. Historical net value by unit and year (2019$, Millions)

Unit	2016	2017	2018	Total
Roxboro 1	[redacted]			
Roxboro 2				
Roxboro 3				
Roxboro 4				
Mayo 1				

Sources: DEP discovery responses; Synapse tabulation.

Confidential Confidential Figure 1 shows the energy value and cost streams for Mayo 1, as well as the unit's net revenues between 2016 and 2018. Individual results for the other four DEP units are shown in Confidential Exhibit RW-2.

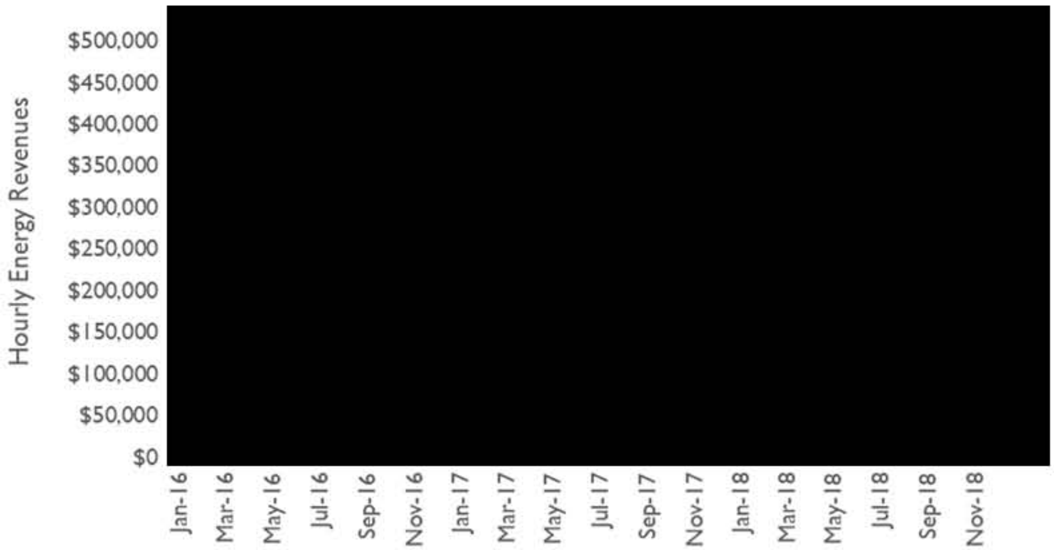
Confidential Figure 1. Mayo 1 historical energy value and costs, 2016-2018



Q Why do the units have higher energy values in 2018 despite producing less energy on average compared to 2016 and 2017?

A This is mainly attributed to the cold snap in early 2018, as shown in Confidential Confidential Figure 2, below. The hourly lambda for the peak times in January 2018 increased to [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] Therefore, the units earned a disproportionate amount of value compared to previous months due to this cold snap. Nonetheless, the overall value of each of the units is overwhelmingly negative despite the increased revenues, due to increased capital expenditures in 2018.

Confidential Figure 2. Hourly energy value for Mayo 1, 2016 to 2018



Q Describe how you arrived at the values in Confidential Confidential Table 4.

A The values presented are based on data related to each unit's energy value, fuel costs, O&M costs, environmental costs, capital costs, and ash management costs.

DEP provided historical hourly generation for each of the units.[14] To calculate each unit's energy value, each unit's converted hourly net generation was

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[14] DEP Response to Sierra Club DR 2-10, attachments "CONFIDENTIAL 2019 DEP NC SC 2-10 Coal HourlyProdCost 2018-2019 xls" and "CONFIDENTIAL 2019 DEP NC SC 2-10e Coal HourlyProdCost 2016-2017 - Supplemental xls".

Although DEP did not specify if these hourly generation values were gross or net, a comparison to the monthly net generation values that were provided in 2-10D indicate that the hourly values were gross. Despite the fact that we had explicitly requested hourly net generation via discovery, DEP provided monthly net generation values to SC 2-10D. In DEP's response to SC 2-10E, the Company provided hourly production costs and hourly generation in MWh. Because the monthly net generation values provided in 2-10D were always smaller than the hourly generation values aggregated to the monthly level provided in 2-10E, it is valid to assume the hourly values are gross. For example, the net generation for Mayo 1 in November 2017 was reported by DEC in 2-10D to be [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] However, when the hourly MWh values for Allen 1 in May 2016 from 2-10E are summed, the result is zero. Because negative hourly generation values never appear in 2-10E, the values must be gross.

To convert the hourly gross generation to hourly net generation, the hourly gross values were multiplied by a net-to-gross ratio. This ratio was calculated by dividing the provided monthly net generation by the aggregated hourly gross generation for each unit, month, and year.

multiplied by the relevant hourly DEP system lambda[15] as provided in discovery.[16]

When asked to provide ancillary services revenues, DEP responded that "The Company does not maintain this information by plant."[17] Due to the lack of information, I estimated ancillary services revenues for the Company using the 2019 historical ratio of the ancillary services price to the load weighted energy price from the PJM State of the Market 2019 report.[18] The resulting number (2.64 percent) was multiplied by the previously calculated energy value and the product was taken as an ancillary services revenue.

DEP provided the total fuel cost burned at the plant-level, and these costs were allocated based on annual generation levels to get unit-level fuel costs.[19]

DEP also provided O&M costs at the plant-level. Although it is standard to show fixed O&M costs separately from non-fuel variable O&M costs, DEP stated in discovery that "the Company does not identify historical costs as either fixed or variable."[20] For this reason, the O&M costs are shown as one category and the plant-level costs are divided into unit-level costs using annual generation levels.

DEP provided plant-level capital costs that were classified by category.[21] Specifically, costs were labeled as "Coal Combustion Products" or "Fossil Hydro Operations". Therefore, we were able to separate costs accordingly. Because all capital costs were provided at the plant-level, they were allocated to individual units based on nameplate capacity.

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[15] The term "system lambda" refers to the marginal cost of electricity in a system and, in an electricity market, is the locational marginal price of energy in a given hour.

[16] DEP Response to Sierra Club DR 2-10, attachment "SCDR_2-10a_DEPSystemLambda_2016-2018-Supplemental xls".

[17] DEP Response to Sierra Club DR 2-9l-o.

[18] Table 1-8, *PJM State of the Market- 2019*, Available at https://www monitoringanalytics.com/reports/PJM_State_of_the_Market/2019.shtml

[19] DEP Response to Sierra Club DR 2-9, attachment "CONFIDENTIAL_DEP Sierra Club DR 2-9i_2016-Oct2019_Supplemental.xls".

[20] DEP Response to Sierra Club DR 2-1.

[21] DEP Response to Sierra Club DR 2-9, attachments "2019 DEP NC SC 2-9 j,k Capex DEP 2016-2017-Supplemental xls" and "CONFIDENTIAL 2019 DEP NC SC DR 5-1 2018 Capital xls"

DEP also provided cost estimates for coal ash remediation projects by plant.[22] These values were allocated to individual units based on nameplate capacity size.

Fuel, O&M, capital costs, and coal ash management costs were subtracted from each unit's energy value to arrive at annual net value.

Q Did you evaluate the economics of the plants without the historical capital expenditures?

A Yes. The results of the economic analysis that exclude historical capital expenditures are shown in Confidential Confidential Table 5. Due to the increase in energy value as a result of the January 2018 cold snap, when capital costs are removed, Roxboro Units 1 and 2 show a slight net positive value in 2018. All other units remain net negative in that year.

Confidential Table 5. Historical net value by unit and year, excluding capital expenditures (2019$, Millions)

Unit	2016	2017	2018	Total
Roxboro 1	[redacted]			
Roxboro 2				
Roxboro 3				
Roxboro 4				
Mayo 1				

Q What are your recommendations to the Commission with regard to any request for recovery of past spending on capital projects at DEP's coal units?

A I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEP's units had negative net value from 2016 to 2018. DEP made capital investments in these coal-fired units either without evaluating the economics of continuing to operate the units, or despite the fact that the units had negative value to DEP ratepayers. Capital spending during this time period should

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[22] DEP Response to Sierra Club DR 2-18, attachment "DEP SC 2-18.xlsx".

be disallowed until DEP provides evidence of an analysis demonstrating the value of the investment that was performed at the time the investment decision was made.

VI. FORWARD-LOOKING ECONOMIC STATUS OF DEP COAL UNITS

Q Did you also evaluate the forward-looking economic performance of DEP's coal units?

A Yes. I analyzed the projected energy value of DEP's coal units in each year from 2019 to 2029 using data provided by the Company.

Q Please summarize the results of that forward-looking economic analysis.

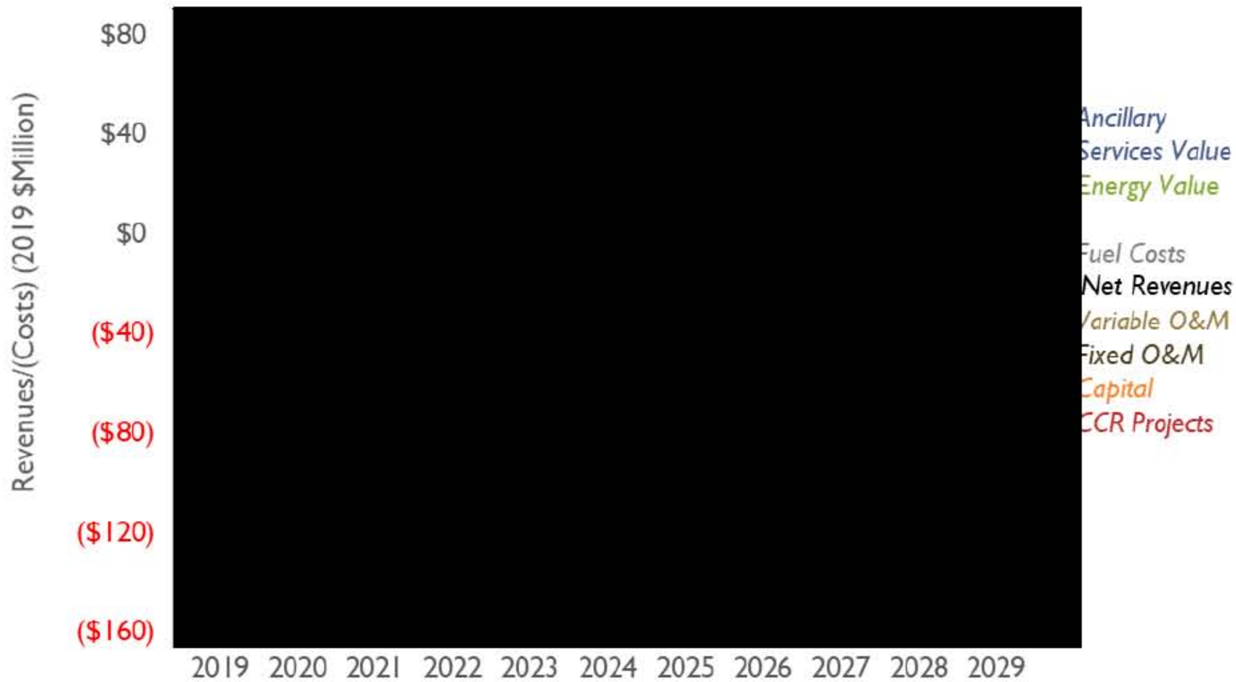
A Based on DEP's projections, I find that the Company's coal units are likely to remain uneconomic through 2029. Confidential Confidential Table 6 indicates that each of DEP's units is projected to have a negative net value in each year from 2019 through 2029.

Confidential Table 6. Forecasted net value by unit and year (2019$, Millions)

Unit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Roxboro 1	[redacted]										
Roxboro 2											
Roxboro 3											
Roxboro 4											
Mayo 1											

Confidential Confidential Figure 3 shows the projected energy value and cost streams for Mayo 1, as well as the unit's net revenues between 2019 and 2029. Results for the remaining DEP units are shown in Confidential Exhibit RW-3.

Confidential Figure 3. Mayo 1 projected value and costs, 2019 to 2029



Q Describe how you evaluated the forward-looking economic performance of DEP's coal units.

A The net values presented are based on DEP data related to each unit's projected energy revenues, fuel costs, O&M costs, and capital costs.

DEP declined to provide specific forecasted avoided energy costs or projected energy market prices requested through discovery. In response to discovery follow ups, DEP provided their avoided cost energy rate schedule and its supporting calculations.[23] I calculated the hourly weighted average rate using the Company's avoided energy cost for Transmission Connected PURPA qualifying facilities (variable rate structure) provided in the attachment.[24] The rate was taken

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[23] DEP Response to Sierra Club DR 3-15, attachment "Avoided Cost_PP rate schedule.pdf".

[24] This was done by multiplying the number of on-peak and off-peak hours for each season by the corresponding energy credit. I divided the product by 8760 to produce the weighted annual average energy credit.

to be in 2018$ and converted to 2019$ for the duration of the analysis period.[25] This avoided cost of energy rate was used to calculate projected energy revenues for each unit.

As mentioned above, I also requested data relating to forecasted ancillary services revenues in discovery, but DEP's response was that "The Company does not calculate…unit specific revenues."[26] Due to the lack of information, I estimated forward-going ancillary services revenues for the Company using the 2019 historical ratio of the ancillary services price to the load weighted energy price from the PJM State of the Market 2019 report.[27] The resulting number (2.64 percent) was multiplied by the avoided cost of energy rate and the product was taken as an ancillary services revenue rate.

DEP directly provided unit-specific capacity, capacity factors, fixed O&M, fuel costs, and capital costs based upon its 2019 IRP studies.[28] DEP also provided unit-specific capital costs and fixed O&M costs for Mayo 1, Roxboro 3, and Roxboro 4 based upon its 2019 depreciation study with accelerated retirement dates.[29] The values from the Company's "No CO_2 Constraint" IRP analysis were used as given for all units except for Mayo 1, Roxboro 3, and Roxboro 4. For those three units, the capital expenditures and fixed O&M data provided in the IRP study were replaced with the updated values from the depreciation study to account for the accelerated retirement dates. Specifically, the generation, variable O&M costs, and fuel costs were adjusted to zero in the years following the units' retirements.

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[25] DEP Second Supplemental Response to Sierra Club DR 2-14.

[26] DEP Response to Sierra Club DR 2-13.

[27] Table 1-8, *PJM State of the Market- 2019*, Available at https://www monitoringanalytics.com/reports/PJM_State_of_the_Market/2019.shtml

[28] DEP Response to Sierra Club DR 2-13, attachment "CONFIDENTIAL 2019 DEP NC SCDR_2-13_a-o_t_DEP_CONFIDENTIAL.xlsx".

[29] DEP Response to Sierra Club DR 2-5, attachment "CONFIDENTIAL 2019 DEP NC_SierraClub_DR2-5_Nov2019DEPRetirementAnalysis.xls".

DEP directly provided forecasted ash management costs through 2040 by plant.[30] These costs were allocated to each unit using nameplate capacity.

Fuel, O&M, capital costs, and forecasted coal ash management costs were subtracted from energy revenues to arrive at net revenues for each plant and each year.

Q What are the implications of these uneconomic results for ratepayers?

A The negative values associated with DEP's coal units means that ratepayers are paying, and will continue to pay, for the uneconomic operation of the Company's coal fleet.

Q Do your findings regarding the recent negative values associated with DEP's coal units indicate that the Company should retire all of its coal units immediately?

A No. Retirement of DEP's entire coal fleet at once would likely lead to reliability issues in DEP's service territory. It is also possible that retirement of a portion of DEP's coal fleet may improve the economics of the remaining coal units. However, the recent net losses of DEP's coal units should, at a minimum, encourage DEP to perform a rigorous economic assessment of alternative retirement dates for each of its units. This assessment would include analysis of the services that the system needs in absence of the retiring units, and the most cost-effective replacement resources that provide these necessary services.

Q Your analysis shows that DEP's coal units have negative value to its customers. Is that a risk for other DEP assets as well?

A Yes. Just as competition from gas resources has challenged the economics of coal units, competition from renewable and storage resources are now challenging new and existing gas units. DEP's 2019 IRP Update calls for new combined cycle units in 2024 and 2026. In addition, DEP is likely to rely on new gas units as

[30] DEP Response to Sierra Club DR 2-18, attachment "DEP SC 2-18.xlsx".

replacement resources in an analysis of alternative retirement dates for the Company's coal units. However, recent trends show that it can be cheaper today to build new renewable-plus-storage units than to build ***new*** gas units. Forecasts suggest that in the future, it will be cheaper to build new renewable-plus-storage units than to continue operating ***existing*** gas units.[31] This means that new and existing gas units are likely to become stranded assets.

New large combined cycle units are not nimble or modular, need large lead time to construct. If the load the units are planned to meet does not materialize, there is no way for DEP to scale the asset down. Existing coal plants can be retired in a staged manner and replaced incrementally with solar, battery storage, and energy efficiency in quantities that match near-term need and allow for customers to benefit from resource cost declines.

Q What is a stranded asset?

A A stranded asset is one that no longer has value or produces income. It is important to consider stranded asset risk for large gas units because the costs to construct them are usually recovered by utilities from their customers over many decades. This risk is particularly relevant to any new gas units that might be proposed as replacement resources for any of DEP's retiring coal units, and to those new units called for in the 2019 IRP Update.

If conditions in the electric sector cause a new or existing gas unit to no longer be used and useful, either the Company's customers or its shareholders will be burdened with the costs of a non-performing unit for the remainder of its depreciable life. Such conditions might include cost declines associated with renewables and storage, a declining cap on carbon dioxide (CO_2) emissions, or both.

[31] Exhibit RW-5. Rocky Mountain Institute. 2019. *The Growing Market for Clean Energy Portfolios.*

Q Are there additional reasons that DEP should evaluate alternative retirement dates for its coal units?

A Yes. On October 29, 2018, Governor Roy Cooper signed Executive Order 80, which directed the North Carolina Department of Environmental Quality to develop a Clean Energy Plan. That Plan was released in October 2019, setting a goal to reduce emissions of CO_2 from the electric sector by 70 percent below 2005 levels by 2030.[32] In a separate docket, DEP stated that in order to reduce emissions commensurate with North Carolina goals, as well as its own corporate goals, it would need to accelerate the pace of coal plant retirements and replace those units with low-emitting resources.[33]

Duke Energy, DEP's parent company, also has its own carbon-reduction goals, which are to cut CO_2 emissions by 50 percent or more by 2030 and to attain net-zero emissions by 2050.[34] New combined cycle units built in 2024 and 2026 will be less than 30 years old by 2050. Give that the typical economic life of a combined cycle plant is 30 to 40 years, it is hard to see how Duke can both meet its 2050 CO_2 emissions goal and operate a new plant through its full economic life.

Q Are these emissions goals relevant to the stranded asset risk faced by new gas units that you discuss, above?

A Most definitely.

Q Is there evidence that other state regulators are making decisions about new gas units based on the risk that they will become stranded assets?

A Yes, especially in recent cases, state regulators are regularly citing stranded asset risk as one of the main reasons why they have rejected proposed gas units:

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[32] North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Available at: https://files nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[33] Duke Energy Progress. Response to Friesian Holdings Data Request 2-8. Docket No. EMP-105, Sub 0.

[34] Duke Energy. *Global Climate Change*. Available at: https://www.duke-energy.com/our-company/environment/global-climate-change.

- In March 2018 the Arizona Corporation Commission rejected the integrated resource plans of the state's utilities due to their reliance on gas units and the associated risk of stranded assets. The Commission placed a nine-month moratorium on new gas units larger than 150 MW while the utilities modeled scenarios with high penetrations of renewables and storage.[35] That moratorium was then extended for an additional six months.[36]

- In April 2019 the Indiana Utility Regulatory Commission (IURC) rejected an 850 MW gas plant proposed by Vectren, citing concerns that the plant could become a stranded asset as cost of renewables declines and customer demand changes. The IURC directed Vectren to evaluate alternatives to a large, centralized generating station.[37]

- In October 2019 the Minnesota Public Utilities Commission rejected a proposal from Xcel Energy to purchase the 720 MW Mankato combined-cycle gas plant due to stranded asset concerns if the plant were to close early due to the decline in renewable and storage costs.[38]

Q What are your recommendations to the Commission with regard to any request for recovery of future capital investments at DEP's coal units?

A I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEP units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers. The cap could decline as units approach their respective retirement dates. The cap could also be contingent upon the results of DEP's unit retirement study, to be included with the 2020 IRP.

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[35] Utility Dive. March 15, 2018. *Arizona regulators move to place gas plant moratorium on utilities.* Available at: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/.

[36] Utility Dive. February 11, 2019. *Arizona extends gas plant moratorium, punts on PURPA reforms.* Available at: https://www.utilitydive.com/news/arizona-extends-gas-plant-moratorium-punts-on-purpa-reforms/548072/.

[37] Utility Dive. April 25, 2019. *Indiana regulators reject Vectren gas plant over stranded asset concerns.* Available at: https://www.utilitydive.com/news/indiana-regulators-reject-vectren-gas-plant-over-stranded-asset-concerns/553456/.

[38] Utility Dive. October 1, 2019. *Minnesota rejects Xcel's 720 MW Mankato gas plant purchase over stranded asset concerns.* Available at: https://www.utilitydive.com/news/minnesota-rejects-xcels-720-mw-mankato-gas-plant-purchase-over-stranded-as/564029/.

Similar action has been taken in other jurisdictions. The Georgia Public Service Commission, for example, recently applied a cap to capital spending at the utility's Bowen plant in the recent 2019 proceeding.[39]

Q Do you offer any recommendations related to your discussion of stranded asset risk for new gas units?

A Yes. I recommend that in future rate cases, DEP be required to demonstrate that its gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. If DEP cannot make such a demonstration, those units should be removed from rate base.

VII. PRUDENCE OF DEP INVESTMENTS IN ITS COAL UNITS

Q Does DEP offer support for the prudence of its investments in its coal units?

A DEP offers limited support for the prudence of its investments through the Direct Testimony of Julie K. Turner, which describes in a single paragraph the Company's "cost management program" and management oversight of project budgeting and cost reporting.[40] Ms. Turner also presents data on the Equivalent Availability Factors (EAFs)[41] and Equivalent Forced Outage Rates (EFORs)[42] for DEP's coal units and compares them to NERC averages.[43]

Q Has DEP demonstrated the prudence of its historical capital investments in its coal units, for which it is seeking cost recovery?

A No. In order to demonstrate prudence in the context of utility planning, DEP would need to show that its decision to commit to a particular power plant

[39] Georgia Public Service Commission. 2019. Docket No. 42310. Order Adopting Stipulation as Amended. Attached as Exhibit RW-4.

[40] Direct Testimony of Julie K. Turner. Page 7, lines 18-23 and page 8, lines 1-3.

[41] Equivalent Availability Factor measures the percent of time that a unit is able to operate at full power if needed.

[42] Equivalent Forced Outage Rate measures the percentage of unit failure in terms of unplanned outage hours and equivalent unplanned derated hours.

[43] Direct Testimony of Julie K. Turner. Page 11.

construction project is justified, based on conditions at the time the decision was made. Planning prudence includes consideration of a reasonable set of alternatives, the use of appropriate models and methodologies, and the collection and application of current forecasts and data. Costs that are found by regulators to have been incurred imprudently should generally be disallowed from rates. Similarly, assets that are not used and useful should be removed from rate base. Customers should not be asked to bear the burden associated with unjustified system planning decisions.

Q What do you mean by "used and useful" in this context?

A The "used" part of the "used and useful" standard is relatively straightforward. Specifically, regulators should determine whether a particular asset is physically used in providing service to customers. Examples of equipment not "used" in providing service can include power plants that have been retired from service, environmental retrofit equipment that is not operated, transmission or distribution equipment that has been removed from the grid, and previously installed meters that are uninstalled as part of a meter replacement program.

The "useful" portion is more complex, as a particular item can be used in providing service but not be economically useful. For example, there may have been a power plant construction project that was planned in a prudent manner but may operate at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee. In such a circumstance a regulatory commission may find that the plant is prudent and used, but not economically useful in providing service to customers.

Q Why are these ratemaking concepts important in this docket?

A DEP is effectively requesting that the Commission determine that its past and future capital expenditures represent prudent investments in its coal fleet. I understand that the Commission applies a presumption of prudence to utility expenditures in some circumstances. There have been no other dockets before the

Commission to determine whether DEP's capital expenditures were prudent prior to the Company spending the money, or whether DEP's coal units are "used and useful." Therefore, it is important that the Commission consider the economics of each of the units when ruling on DEP's application in this docket. While the Commission might consider DEP's coal fleet "used" because it provides energy to ratepayers, given the fact that the coal units are providing energy uneconomically, and increasing costs to DEP ratepayers, they are not currently "useful."

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My primary findings indicate that all DEP's coal units operated uneconomically for the three years between 2016 and 2018. I estimate that each of the coal units had negative net value of between [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] from 2016 to 2018. Despite these net losses, DEP continues to determine unit retirement dates for its coal fleet based solely on depreciation studies and continues to invest in its uneconomic coal units.

My analysis shows that each of DEP's coal units will continue to operate uneconomically in the future. DEP has not provided any economic assessments of the continued operation of its coal-fired units, even as low gas prices and declining costs for renewables have disadvantaged many coal units across the country. Thus, the Company has not demonstrated that continuing to invest in its coal fired units is a prudent decision and provides value to ratepayers.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. I recommend that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEP's units had negative net value from 2016 to 2018.

Capital spending during this time period should be disallowed until DEP provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made.

2. Similarly, I recommend that the Commission disallow recovery of ongoing operations and maintenance (O&M) expenses at DEP's coal units, given that DEP's coal units are projected to continue to have negative value in the future.
3. I recommend that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEP units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.
4. I recommend that in future rate cases, DEP be required to demonstrate that its gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. If DEP cannot make such a demonstration, those units should be removed from rate base.

Q Does this conclude your direct testimony?

A Yes, it does.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-2, SUB 1219

My name is Rachel Wilson and I am a Principal Associate with Synapse Energy Economics, Inc., a research and consulting firm specializing in electricity industry regulation, planning, and analysis. At Synapse, my work focuses on a variety of issues relating to electric utilities, including integrated resource planning, resource adequacy, electric system dispatch, environmental regulations and compliance strategies, and power plant economics.

The purpose of my testimony is to evaluate the economics of the coal-fired units owned by Duke Energy Progress (DEP or the Company) and assess the prudence of the Company's capital investments in these units as well as its operation and maintenance costs.

Using data provided by DEP, I evaluated the net value of each of the Company's coal units between 2016 and 2018. The input data set included each unit's energy and ancillary values, fuel costs, O&M costs, environmental costs, capital costs, ash management costs, hourly generation, and the DEP system lambda. These various costs that I mention were subtracted from each unit's energy value to arrive at annual net value. (Because the information provided by DEP on which I based my analysis is confidential, the Company has also deemed the dollar values resulting from my analysis confidential—that is the amount by which the costs to operate the units exceeded the value provided by the units.)

My primary findings indicate that all DEP's coal units—which include the unit at the Mayo plant and the four units at the Roxboro plant—operated uneconomically for at least the combined three-year period from 2016 through 2018. Despite these net losses, DEP continues to set unit retirement dates for its coal fleet based solely on its depreciation study, which does not reflect the actual economic value, or lack thereof, to ratepayers.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-2, SUB 1219

In addition, my analysis shows that each of DEP's coal units will continue to operate uneconomically in the future. I conducted a similar analysis evaluating the forward-looking economic performance of DEP's coal units for years 2019 through 2029 and found that, based on DEP's projections, its coal units are likely to remain uneconomic through 2029, with each unit having a negative net value in each year from 2019 through 2029.

Nevertheless, DEP is seeking to recover $107.4 million for operations and maintenance expenses and a substantial amount of capital expenditures—the dollar amount which is provided in the confidential portion of my testimony—incurred at its coal plants in 2018. Future O&M and capital costs could be even higher. DEP has not demonstrated the prudence of its coal unit costs for which it is seeking cost recovery. Specifically, the Company has not demonstrated that its decision to incur additional capital expenses at its individual coal units rather than retiring them is justified. Instead, the Company assumes that its coal units will continue to operate until the dates identified in its most recent depreciation study—that is, 2028 for Roxboro Units 1 and 2, and 2029 for Mayo Unit 1, Roxboro Units 3 and 4. These life span estimates were not based on economic analyses of alternative retirement dates.

In addition, DEP's continued operation of and investment in its aging coal fleet ignores Governor Roy Cooper's Executive Order 80 and the subsequent North Carolina Department of Environmental Quality Clean Energy Plan. That Plan, released in October 2019, sets the goal of 70 percent reduction of carbon dioxide emissions below 2005 levels from the electric sector by 2030. And Duke Energy has its own carbon-reduction goals of cutting carbon dioxide emissions by 50 percent or more by 2030 and to attain net-zero emissions by 2050. Continued investment in all of DEP's coal units does not reflect a plan to meet these emission reduction goals.

Summary of Direct Testimony of Rachel Wilson, for Sierra Club
Docket No. E-2, SUB 1219

Given this, and based on the findings of my analysis of coal unit economics, I have two recommendations for this Commission: first, that the Commission disallow past spending on capital projects incurred between the 2017 rate case and this rate case, given that the data show that all of DEP's coal units had negative net value in 2016, 2017, and 2018; and second, that the Commission place a cap on future capital expenditures intended to prolong the lives of the DEP coal units as generating assets, and require the utilities to come to the Commission for approval of any expenditure that exceeds that cap before the expenditure can be recovered from ratepayers.

MS. LEE: Thank you, sir. We also request that prefiled Wilson -- Sierra Club Wilson Exhibits 1, 4, and 5, and confidential Sierra Club Wilson Exhibits 2 and 3 be marked for identification as they were premarked.

COMMISSIONER CLODFELTER: Granted and will be so ordered.

(Sierra Club Wilson Exhibits 1, 4, and 5, and Confidential Sierra Club Wilson Exhibits 2 and 3 were identified as they were marked when prefiled.)

MS. LEE: Thank you. And finally we move that the live testimony of Ms. Wilson given in the DEC proceeding located at DEC transcript Volume 18, beginning on page 174, line 7, continuing through page 207, line 5, be moved into the record in this proceeding at this time.

COMMISSIONER CLODFELTER: Any objection to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objection, motion is granted.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume

18, page 174, line 7 through page 207, line 5 was copied into the record as if given orally from the stand.)

Q. Ms. Wilson, my name is Andrea Kells. I'm here on behalf of Duke Energy Carolinas. Good morning.

A. Good morning.

Q. And you're here today testifying on behalf of the Sierra Club; is that correct?

A. That's correct.

Q. Would you agree the Sierra Club is an environmental organization?

A. Yes, I believe that they call themselves such.

Q. Are you familiar with one of the Sierra Club's projects called the Beyond Coal Campaign?

A. I am familiar with that, yes.

Q. And are you familiar with the stated goal of that campaign being to shut down all coal plants in the U.S., or work towards that goal?

A. Generally, yes.

Q. And are you aware of Duke Energy's carbon emissions goals of reducing such emissions by 50 percent below 2005 levels by 2030, and achieving that zero emissions by 2050?

A. I am aware of those goals, yes.

Q. Would you agree that, to achieve those goals, Duke Energy will need to transition away from relying on its remaining active coal plants going forward?

A. I believe that's true, yes. Though there are, I think, several model scenarios that show different pathways to achieving that carbon reduction goal.

Q. Would you agree that DEC has about 20,000 megawatts of total generation capacity on its system?

A. Subject to check, that sounds correct.

Q. Would you agree that about 6,700 megawatts of that amount is coal-fired capacity?

A. I -- it was my understanding that it was slightly higher than that number, but it could be based on a nameplate versus summer or winter reading.

Q. Okay. And if you want to reference it, it's on Company witness Immel's direct testimony on page 3, line 12.

A. Thank you.

Q. Would you agree that the Company, DEC, has an obligation to provide safe and reliability electric service to its customers?

A. Yes, I would.

Q. And would you agree that, as the Company makes that transition away from reliance on coal we discussed a moment ago, it has to make that transition while continuing to meet that obligation to customers?

A. That's correct, yes.

Q. Now, your testimony recommends that the Commission disallow recovery of all capital investments the Company made in its coal fleet between the previous rate case and this one; is that correct?

A. Yes. I believe, though, I placed that contingency on the fact that the Company, DEC, should present a demonstration that its units are, in fact, economic. And if it can't present such a conclusion, then at that point the capital expenditures should be disallowed.

Q. And so when you talk about the units being economic, are you referring to the analysis that you did of the coal fleet?

A. That's correct.

Q. And your analysis looked at what you termed

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the net economic value of the fleet?
A. It did.
Q. And you conducted that study in late 2019, early '20, I'm guessing, just based on when we filed the case and your testimony was filed?
A. That's right, yes.
Q. And you relied for that analysis on data the Company provided through discovery?
A. That's correct.
Q. So that data included actual known costs incurred to maintain the coal units during the 2016 to '18 time frame?
A. That's right.
Q. And it also included actual known marginal costs of electricity on the system during that same time frame?
A. In the form of a system wind-down, yes. I'm sorry, that reflects net energy value. In -- my analysis includes fuel costs, variable O&M, fixed O&M, and then capital expenditures.
Q. And your analysis wasn't intended and did not analyze what the Company should have done with the information available to it at the time it incurred those costs to maintain those units, did it?

A. It did not.

Q. And in your testimony, did you present any feasible alternative the Company should have chosen instead of making any of these investments?

A. The Company has an obligation to look at replacement alternatives, whether that be adding new generation, investments in energy efficiency or demand response. I didn't analyze any of those alternatives. My analysis simply looks at -- it's a cash flow analysis of the Company's coal-fired units, and it looks at the net energy value on the system, comparing the cost and energy benefits derived from the coal units over the 2016 to 2018 time period.

Q. Okay.

A. And it's not an IRP-like replacement analysis.

Q. Okay. And did your testimony identify any particular investment the Company should not have made?

A. No single investment, no. And as I point out in my testimony, the retirement of one unit would affect the relative economics of another. This doesn't look at the units as a whole; it takes them one by one. And if you were to look at the net energy values in my tables and in my testimony, you can see that they are,

in fact, different for each of the units.
Q. And are you familiar with the standard for cost recovery in North Carolina utility rate cases?
A. Not specifically, no.
Q. Okay. Are you generally aware that the utilities seeking recovery must show that its costs were reasonably and prudently incurred?
A. That seems correct, yes.
Q. And would you agree that that standard is applied based on the information the utility had available to it at the time?
A. That's generally how prudence is determined, yes.
Q. And are you also generally aware that, if a party wants to challenge the utility's cost, that party must identify specific instances of imprudence and provide a prudent alternative the utility should have chosen instead?
A. I was not aware of that, no.
Q. Can you refer to what was premarked as DEC Exhibit 3.
A. Yes. Give me one second.
Q. Sure.
MS. KELLS: And, Chair Mitchell, this is

actually -- DEC Exhibit 3 is the February 24, 2020, final order in the Dominion rate case, E-22, Sub 562, and I believe that's been taken judicial notice of, and so we don't need to make it a cross exhibit.

CHAIR MITCHELL: Okay. And we have taken judicial notice of that -- of this decision.

Q. Okay. Ms. Wilson, just let me know when you're there.

A. I have it, yes.

Q. And would you please turn to page 121 of the order? The page number is at the bottom.

A. (Witness peruses document.)

I'm sorry, I don't actually see the page numbers on this document.

Q. Okay. So I will -- so you're looking at DEC Exhibit 3?

A. Yes. Let me look in a different application. Sorry.

Q. That's okay.

MS. LEE: I'm looking as well, and this is the document we downloaded from Duke's data site. There are no page numbers on my version either.

MS. KELLS: Sorry about that.
THE WITNESS: I have the PDF page 121.
Is the heading at the top "discussion," and subheading "applicable legal principles"?
Q. That is right.
A. Correct, then I am there.
Q. All right. There is a paragraph that starts down there near the bottom of the page, and it is not completed. But the paragraph starts "when setting"; do you see that paragraph?
A. I do, yes.
Q. And if you go one, two, three, four, five lines down, there's a sentence that starts "challenging prudence"; do you see that?
A. I do.
Q. Would you please read that sentence.
A. "Challenging prudence requires a detailed and fact-intensive analysis, and the challenger is required to; one, identify specific and discrete instances of imprudence; two, demonstrate the existence of prudent alternatives; and three, quantify the effects by calculating imprudently incurred costs. Harris order at 14-15."
Q. Thank you. And I know you just read words on

a page, but does that sound consistent of what I asked you before about the standard for challenging prudence?

A. It does sound consistent, yes.

Q. And are you familiar with the concept of the cost of property used and useful as it's used in North Carolina?

A. I'm generally familiar with the used and useful standard, yes.

Q. And, in fact, your testimony discusses your interpretation of that standard, doesn't it, on page 21?

A. It does.

Q. And in discussing the term "useful" -- I'm on page 21, I think this is around line 9 or 10.

A. This is in my direct?

Q. Yes. Your direct testimony, page 21.

A. (Witness peruses document.)

Okay.

Q. So I was on line 9 or 10. And so in discussing the term "useful," you said there that:

"Where a power plant was planned prudently but may operate at higher costs than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, a Commission may find the plant prudent and used but not economically useful."

Did I read or paraphrase that correctly?

A. You did, yes.

Q. And you're not a lawyer, are you, Ms. Wilson?

A. I am not, no.

Q. Has this Commission ever adopted your definition of the word "useful" in applying this standard?

A. I don't know if this Commission has adopted that particular definition, no.

Q. Have you testified before this Commission before in a rate case?

A. Not in a rate case, no.

Q. Has any other commission -- utility commission accepted your specific interpretation of the term "useful" based on your testimony?

A. I can't recall offhand if I've ever put forth a definition of "useful" in testimony before a commission. I think the answer is no, but I may be wrong about the timing of testimonies that are filed.

Q. Okay. You've submitted testimony in several jurisdictions; is that right?

A. That's right.

Q. And so one of those, in addition to here in North Carolina, is you've testified on behalf of the Sierra Club in Georgia; is that right?
A. That's correct.
Q. And you cite to that case or one of them that you've been a part of in your testimony on page 20 when you make the recommendation the Commission put a cap on the Company's future capital investments in its coal fleet; do you recall that testimony?
A. I do, yes.
Q. And before we talk about the Georgia case, is it your understanding that, in North Carolina rate cases, when you look at costs incurred during a historical test year updated through a certain period to determine if they're reasonably and prudently incurred?
A. That's correct.
Q. And that's different, isn't it, than if the state used, for example, a forward-looking test year or some model that allowed the Commission and the parties to review investments in advance of incurring them; would you agree with that?
A. Using a historical year would be different than using a forward-looking year, yes.

Q. And so back on your testimony, on page 20, line 11, you cite to the Georgia Public Service Commission as having imposed a cap like you propose here?

A. That's correct. I'll note that that was in an IRP docket, not in a rate-case docket.

Q. Thank you for that clarification.

And you attach that order in that case as Exhibit 4 to your testimony, correct?

A. Yes.

Q. And the Georgia Commission adopted a stipulation in that case, didn't it?

A. It did.

Q. Did the Sierra Club sign on to that stipulation?

A. I can't recall.

Q. Well, if you will look at the order that you've attached as your Exhibit 4.

A. Give me one second.

Q. Sure.

A. (Witness peruses document.)

I am there.

Q. And will you turn to page 8 of that order.

A. I see that.

Q. And so near the bottom there is a sort of subheading that says "nonsigning party's positions"; do you see that?
A. I do.
Q. And then if you turn over to page -- well, there's page 9, and then if you go to page 10, near the bottom you can see that Sierra Club is listed as a nonsigning party?
A. I do see that.
Q. And so would you agree that Sierra Club was a nonsigning party to the stipulation in that case?
A. Yes, I would.
Q. And the Georgia Commission in that case specifically denied nonsigning parties' recommendations; did it not?
A. I believe so, yes.
Q. All right. Ms. Wilson, would you agree that the Company's coal units are subject to certain state and federal environmental requirements coming under CAMA, federal CCR rule, and ELG rules?
A. Yes, I would.
Q. And would you agree that almost half the capital investments the Company's made in its coal fleet and is asking to recover here were made to comply

with those environmental requirements?

A. I would agree with that, yes. However, it's my understanding of the CCR rule, at least, that certain of the retrofit expenditures might have been able to be avoided if the Company's committed to retiring their coal units by a certain date. I don't specify in my testimony the volume or the amount of capital investment that might have been able to be avoided, but it's my understanding that there is a portion of that that might have been avoidable.

Q. Okay. Yeah. And so you kind of led me to my next couple of questions.

So is it your general understanding that some of those requirements had to be done regardless of whether the units continued to operate? Things like installing the lined basins, for example, had to be done regardless of whether a unit operates or not, right?

A. That's correct, yes.

Q. And then aside for projects like that, if the Company was going to continue to operate these units, there were additional projects that it needed to do; for example, the dry bottom ash conversions, correct; would you agree with that?

A. Yes, I would.

Q. And as you suggested a minute ago, if the Company had not done those additional environmental projects that were required in order to continue running those units, it would have needed to shut them down, correct?

A. That's right.

Q. In your opinion, was that a feasible path for the Company to have chosen, to have not done these projects and to shut down these units?

A. I haven't analyzed that in my testimony. My testimony simply looks at the net energy value over the three-year period. I'll note that my confidential Table 5, in fact, removes capital expenditures from the analysis. And I see similar results in 2016 and 2017 in that each of the units incurred net negative value. And that it was only in 2018, which had a very cold January period, that those units are then positive, with the overall effect being that the majority of them over the combined period have been that negative energy value.

Q. And your study that produced those results that you're discussing, your study didn't analyze how -- or consider how it would be feasible to shut down all those units and continue to meet service obligations, did it; that wasn't its purpose?

A. It did not. And, in fact, I say that reliability would likely be effected if the unit -- if all of the units were to shut down. And that it wasn't my recommendation, in fact, that DEC shut down all of those units immediately. But that it look at the unit retirements, stack those unit retirements and determine an economic pathway that's beneficial to ratepayers.

Q. And when you were talking about that in your testimony where you said that retiring the entire fleet would likely lead to reliability issues, what you just mentioned, what were you referring to by "reliability issues"?

A. Generally, that the lights would -- could potentially go out. As I think you know, utilities are required to hold a number of megawatts in excess of peak demands, so peak demand plus a required reserve margin. And we were talking about the total generating megawatts in Duke's fleet at the beginning of this question-and-answer period. And, you know, if the Company were to retire 7,000 of 20,000 megawatts, it would leave it with 13,000, which is not sufficient to meet peak load plus a required reserve margin.

There are other different reliability issues that could be caused by the retirement of an entire coal fleet, but, you know, that's the primary issue that I was referring to.

Q. Thank you. And do you think it's possible there could also be reliability issues with retiring, say, like a coal station or a subset of units, or did you look at that?

A. I didn't look at that in this testimony. It is certainly possible, depending on the location, but it's also possible that there are a number of solutions that could alleviate that reliability concern.

Q. And so I think you mentioned earlier about the Company hasn't -- well, let me rephrase that. Part of your testimony is that the Company's not justified these investments; is that correct?

A. That's correct, yes.

Q. Would you agree that an analysis of whether or not to do an investment at a particular unit would look at, first, the cost of that investment as a starting point?

A. It would certainly include the cost of the investment. I'll note that -- that, in many instances with coal-generating units across the nation, they are often operating at a net loss, and that includes units in vertically integrated territories, and coal units in market areas simply because of the competitive nature of gas-fired generation and renewables, which push marginal prices down. And, oftentimes, the operating constraints of coal units mean that those units are required to stay online operating at a higher cost even when they're uneconomic, just simply due to ramping constraints and startup and shutdown time periods.

So, you know, this is a challenge that coal units across the nation are facing, and, you know, DEC is certainly not alone in that.

Q. And would you find it reasonable that an analysis of whether to do an investment should also look at sort of the flip side of the cost of the investment, meaning any costs that might come up if the investment is not made and the unit needs to retire?

A. Could you give me an example of what you mean?

Q. Sure. For example, do you think it would be a good idea for the Company or any utility doing an analysis like this to look at the cost of any replacement generation that would be required if the unit were to retire?

A. That's one thing that the Company could look at, sure. And it's my understanding that, in the past, Duke has looked at replacement generation. But I would disagree with their methodology, in that Duke often looks at the retirement of a unit and compares that to replacement with a combined cycle unit or a combustion turbine. It's not, in fact, true that capacity needs to be replaced on a one-for-one basis.

Duke could, instead, take a portfolio approach where it looked at energy efficiency and renewable investments, a smaller gas-fired unit, if necessary. Capacity purchases are another option that could be examined. So the category of replacement generation could, in fact, take a variety of different forms.

Q. And have you looked at what portion of any that -- of the Company's coal-fired fleet it could have replaced with, you know, merchant purchases, purchases for merchant generation, rather than make some of these investments?

A. I haven't looked at that. You know, my understanding is that an all-source RFP issued by DEC would be the best way to get at that information as to what's available in the market.

Q. Are you aware there's not a great amount of excess merchant generation available in the Carolinas?

A. I am not certain that that's true. I have read the opposite in other documents. I haven't seen, you know, specific evidence one way or the other.

Q. Do you recall that the Company provided retirement analyses of Allen station and Cliffside unit 5 through discovery in this case?

A. That's correct, yes.

Q. So I'm going to ask you to look at DEC Exhibit 30.

MS. KELLS: And, Chair Mitchell, this is marked confidential, but I only have a few questions about it, and I've crafted them to not be directed at the confidential part. And so I think we can continue in public session, if you agree to that.

CHAIR MITCHELL: All right. Ms. Kells, I'm looking at the document now. We can proceed in open session. You know, this is a Duke document, so I trust you will avoid discussion of confidential information. So you may proceed.

MS. KELLS: All right. Thank you. So this was premarked as DEC Exhibit 30, so may we mark it now as DEC Wilson Cross Exhibit 1.

CHAIR MITCHELL: All right, for just abundance of caution, we're going to mark this confidential DEC --

MS. KELLS: Confidential.

CHAIR MITCHELL: -- Confidential DEC Wilson Cross Examination Exhibit 1.

MS. KELLS: Thank you.

(Confidential DEC Wilson Cross Examination Exhibit 1 was marked for identification.)

Q. Ms. Wilson, so this is the Company's response to Sierra Club Data Request 2-4.

. Have you seen this document -- set of documents before?

A. I have, yes.

Q. So just to orient us or other folks who may not have looked at it before, the first page of the exhibit is the cover page to this response, and then on the next page it's the request and then a narrative response. And then starting on page 5 -- the entire exhibit is numbered -- there is the study of the early retirement of Allen station. That is a presentation. And then on page 21 starts a series of tables, and that

is the underlying Allen analysis. And then at the back, starting on page 86, is the Cliffside retirement study summary and presentation.
Do you agree that you see all those parts there?
A. I do, yes.
Q. Okay. And is this the information that you were recalling the studies that were done?
A. That's right, yes.
Q. And so I was just going to focus on page 21, which is the first page of the actual analysis of early retirement of Allen station. I had to print mine out really big, so I hope you were able to do the same or have it on a screen.
A. I have it on a screen, yes.
Q. Okay. And so -- and you can see that, just to make sure we're on the same page. It's page 21 and it's top left-hand corner. There's various labels, but one of them says 01.Econ Summary. Do you see that?
A. I do, yes.
Q. And I'll represent to you that this is the summary tab or the first tab of the Allen retirement file.
And so do you see on the most left-hand

column there's a series of costs -- types of costs and cost categories?
A. Yes.
Q. And then across the top, do you see that there are six different what we might call scenarios that each of these costs was evaluated in?
A. I do, yes.
Q. And would you accept, for purposes of these questions, that -- and I'm not going to say any of the numbers, but there are some numbers on this table that are -- if you are looking at color, that are red and in parentheses, and that those indicate where the Company concluded early retirement would avoid costs or save money?
A. Yes.
Q. And would you also accept that the black numbers not in parentheses indicate where the Company concluded that early retirement would incur additional costs?
A. Yes.
Q. And so you can see that, for many of these costs, there are savings in many cases and there are additional costs in many cases; would you agree with that?

A. Yes.

Q. Okay. And back on that left-hand column, in the list of costs, if you go down to the second category that's in bold and it has a green line, it's called capital and FOM costs; do you see that sort of in the middle of the table?

A. I do, yes.

Q. And several lines under that, there's a label for accelerated generation; do you see that?

A. Yes, I do.

Q. And then, again, without stating the numbers, in each scenario there are indicated accelerated generation costs for each of the six scenarios; do you see that?

A. I do.

Q. And then at the bottom of the table, it's labeled "Total retirement savings," and would you agree that, in four of the six scenarios, this study indicated that early retirement would result in additional costs to the Company?

A. Yes.

Q. So based on the results of this study, in your opinion, would it have been prudent for the Company to not make required investments in Allen and retire it early and incur greater costs than it would otherwise?

A. I will say that the results of this study do, in fact, indicate that, but that I would object to a number of the input assumptions that were made in this particular study.

Q. And then I think we've -- I think we've -- I might have asked you this question. If so, I apologize.

In preparing your testimony and analysis, you didn't look at the need for replacement capacity for any of the coal units if they were to shut down; is that right?

A. I did not. There -- first of all, it's unclear whether or not replacement capacity would be needed for all of the units. You know, these units are different sizes ranging from smaller side to the larger side. And if Duke is in a position of excess capacity, it may need not replace, you know, one or more of the smaller units. And there are, again, a number of different replacement options that could be considered.

I don't believe that a replacement needs to be one-to-one in terms of capacity, and so that is perhaps an issue where I would disagree with Duke's analysis.

Q. And you also didn't analyze whether a particular unit would, in fact, need replacement capacity, did you?

A. I did not. Again, you know, my analysis is meant to be more of a cash flow. I am, in fact, requesting that Duke look at a replacement for its coal units. And, you know, my analysis simply indicates kind of a rank order of the units in terms of net energy value in this docket. So it might be a starting point for replacement analysis, but it's certainly not meant to be a replacement analysis.

Q. Did you mention this study in your testimony or exhibits?

A. I did not, no.

Q. And we've been talking about it a bit, but did you analyze the data provided in these documents in preparing your analysis for testimony?

A. I looked at these data. I wouldn't say that I analyzed them, no. And it appears to me that this analysis was done using modeling software, and the name of that software appears in this document. I'm not sure if I'm allowed to say it.

Q. Let's not, just to be careful.

A. Okay. And I didn't employ any sort of modeling software in my analysis.

Q. And you have testified, correct, that the Company has not justified its investments in the coal fleet; is that right?

A. That's correct.

Q. But you decided not to mention this analysis in your testimony, correct?

A. I did not mention this analysis in my testimony, no.

Q. Did you use any of the information the Company provided through discovery to conduct a retirement study of your own with regard to any of the coal units?

A. Not conduct a retirement study in this docket, no.

Q. Thank you, Ms. Wilson.

MS. KELLS: Chair Mitchell, those are all my questions.

CHAIR MITCHELL: All right. Additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: Any redirect for the witness?

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MS. LEE: Just one or two,
Chair Mitchell.
REDIRECT EXAMINATION BY MS. LEE:
Q. Ms. Wilson, you were just discussing this Allen analysis with Ms. Kells, and understanding that the contents of it are confidential, please only answer this question in general terms, keeping that in mind.
You mentioned, in response to one of her questions, that you objected to a number of the input assumptions?
A. That's right.
Q. If you could discuss those without revealing anything confidential, could you please do so?
A. Sure. Ms. Kells referenced the accelerated generation, and this analysis looks at a couple of different options for that accelerated generation. And Duke's input assumptions around that specifically are an area in which I would disagree.
Q. Okay. And to your mind, is this type of analysis, and the one that was conducted for Cliffside, are those comprehensive retirement analyses?
A. No, I don't believe so. These analyses specifically are designed to look at the decision around whether to retire or continue to operate a coal

unit with a specific capital investment in mind. So, in these analyses, DEC was looking at upcoming environmental rules and whether or not it was more economically beneficial to incur those additional costs associated with compliance with the rule or retire those units.

And it's my opinion that now the economics of the United States coal fleet is such that coal units need to be analyzed on an ongoing basis to determine their economic value to ratepayers. It's not enough to look at these units when a specific larger capital investment is required, but to analyze them in an ongoing way to determine whether or not what I'll call sustaining CAPEX is economically beneficial to ratepayers.

Many of these units Duke's included are quite old, and they have lives that took on now past what they were intended to operate when they were constructed. So utilities can continue to invest capital in them to keep them operating, you know, past their originally intended useful lives, and that may not be in the best interest for ratepayers, particularly given the competitiveness of renewable energy today.

Q. Okay. And just one follow-up to that answer.
Given the age of Duke's fleet and the trends that we've seen in the U.S. coal industry -- electric generating industry, I should say -- would your opinion about the need for continuing evaluation, would that continuing evaluation have been needed back in 2015, say?

A. So back in 2015, the trend was -- utilities then were looking at -- they were in a similar situation, but this was with respect to the CSAPR and NOX rules which looked at regulations for SO2, NOX, and mercury. So utilities were faced with the decision then, which was to install an FGD primarily, or other emissions control technologies, or many of them looked at replacement generation with combined cycle or combustion turbine unit, depending on the size.

And the way that the economics kind of were trending in 2015 was that many of the smaller, older coal units, it was more economic to retire them, whereas a lot of the larger, newer units, it was more economic to continue operation with the installation of control technologies. And as -- you know, in just the five years since those dockets were coming up around the country, the new trend has been that larger and newer units have also been retiring. And this is both because of, again, environmental rules and the investments necessary to comply with them, but it's also a matter of economics. And there are a number of coal-fired units that have retired or announced intent to retire in the next five years simply due to economic pressure from competing generators.

MS. LEE: Thank you. I have no further questions at this time.

CHAIR MITCHELL: All right. Questions from the Commissioners, beginning with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I have no questions.

CHAIR MITCHELL: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me.

CHAIR MITCHELL: Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Hughes?

COMMISSIONER HUGHES: Yes.

EXAMINATION BY COMMISSIONER HUGHES:

Q. If I understand your testimony, you seem to be saying clearly that you do not recommend the retirement of DEC's entire coal fleet, and at once would likely lead to reliability issues in the service territory.

How do you reconcile that recommendation with categorically excluding all costs of the coal fleet? I'm just trying to see how you would reconcile or explain that.

A. Sure. So my recommendation was to exclude the capital costs associated with keeping those coal-fired generators online until DEC could demonstrate that those units were economically necessary. And so that involves going back and showing, between 2016 and 2018, that they had, in fact, done an economic analysis demonstrating that those units were cost effective for ratepayers. I haven't seen evidence in this docket that DEC has done that. It may exist and the Company hasn't provided it, but I would -- if it does exist, I would like to see it, and have them provide it in support of their investments in their coal fleet.

Q. And if they had done that and they had seen everything was negative, would you still stand by that you would not want to retire the entire coal fleet immediately?

A. So DEC's analysis would, in fact, take into account replacement capacity, and that takes time to bring online. So, you know, my recommendation isn't that DEC retire its coal fleet now in 2020 or 2021, but rather, you know, it would need to look at replacement capacity in the instance where almost 7,000 megawatts of generation is retiring, determine what is the best economically for ratepayers and make those investments, instead of continuing to invest capital into units that aren't in the economic interest of customers in North Carolina.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions at this time, Madam Chair.

CHAIR MITCHELL: All right. Questions on Commissioners' questions?

(No response.)

CHAIR MITCHELL: Ms. Lee, any questions

on Commissioner's questions?

MS. LEE: No, I don't. Thank you.

CHAIR MITCHELL: Okay. All right. At this time, Ms. Wilson, you may step down. Ms. Lee, I'll entertain a motion from you.

MS. LEE: Thank you, Commissioner Clodfelter. The witness is now available for cross examination.

COMMISSIONER CLODFELTER: Okay. Cross examination. The only party that I have on my notes reserving cross examination is the Company.

MS. KELLS: Yes, sir. This is Andrea Kells for Duke Energy Progress.

COMMISSIONER CLODFELTER: Good morning, Ms. Kells.

MS. KELLS: Good morning.

CROSS EXAMINATION BY MS. KELLS:

Q. And good morning, Ms. Wilson.

A. Good morning.

Q. So in light of the stipulation that was filed earlier this week including your DEC live testimony, I was able to eliminate some of my questions. So I have a few things that I would like to cover with you with respect to DEP, in particular.

A. Okay.

Q. First, would you agree that your testimony in this case recommends the Commission disallow recovery of all capital investments the Company made in its coal fleet between its previous rate case and this case?

A. Yes, it does.

Q. And in making that recommendation, did your testimony specify any particular costs the Company should not have incurred? For example, a particular project at a particular unit?

A. It doesn't specify a particular project or a particular cost, no. Given that my testimony demonstrates that these units were operating economically, then it includes all of the capital costs invested in these units to maintain them over the period.

Q. And when you refer to operating economically, you are speaking based on the analysis you did of the coal fleet; is that right?

A. That's correct. The analysis of the net energy value, what I call the net energy value.

Q. And in doing that analysis, you used data that the Company provided through discovery; is that correct?

A. Yes.

Q. And that included actual data related to costs incurred to maintain these units over the 2016 to '18 time frame; is that right?

A. That's correct.

Q. And did that information also include actual hourly DEP system lambdas during that time frame?

A. The analysis did include those system lambdas, yes.

Q. Would you agree that your analysis -- I think you referred to it as a cash flow analysis -- was not analyzing actually the Commission -- I'm sorry, the Company's decisions that it made at the time it incurred these costs; it was rather focused on what you term the net energy value?

A. That's correct. It wasn't a -- what we had talked about as a replacement study, which is typically done at a specific decision point, and often analyzes one specific investment.

Q. And in your testimony on -- did your testimony offer or recommend other options the Company could have chosen instead of incurring any of the costs it's seeking to recover here?

A. In terms of alternate specific investments, no, it does not.

Q. And you've testified that -- would you agree that you've testified that the Company has not justified its investments that it's seeking to recover in this case?

A. That's correct. Based on this analysis of net energy value and the resulting determinations, I would say no, the Company has not justified ongoing operational expenses for capital investments at the four -- I'm sorry, five units in Progress' service territory.

Q. And do you recall that the Company provided a 2016 analysis of Mayo station through discovery?

A. I do, yes.

Q. And would you please turn to what was marked as -- or premarked as DEP Cross Exhibit 35? And while you're getting that --

MS. KELLS: Commissioner Clodfelter, this exhibit was marked confidential and remains confidential. I have just a couple questions about it very high level, does not get anywhere close to confidential information. If it -- if you're amenable, we could continue in this session.

COMMISSIONER CLODFELTER: Ms. Kells, this is a Duke Progress exhibit?

MS. KELLS: It is.

COMMISSIONER CLODFELTER: And the designation was made by Duke Progress as confidential?

MS. KELLS: It was, yes.

COMMISSIONER CLODFELTER: Then I'm going to trust that the burden is on you to make sure your questions are posed in such a way that they do not elicit or disclose confidential information. We can proceed knowing that you have that burden.

MS. KELLS: Understood. Thank you, sir.

COMMISSIONER CLODFELTER: Ms. Wilson, please -- excuse me. Ms. Wilson, please, in your responses to Ms. Kells' questions, try to refrain from disclosing any information in that exhibit that has been designated confidential.

THE WITNESS: Yes, I will. Thank you.

COMMISSIONER CLODFELTER: Thank you.

MS. KELLS: And, Commissioner, I would ask that this exhibit be marked or premarked. I'm going to try to get it right based on what we did yesterday. Confidential Wilson DEP Cross Examination Exhibit Number 2.

COMMISSIONER CLODFELTER: All right. That would be the next number in sequence, correct?

MS. KELLS: That's right.

COMMISSIONER CLODFELTER: All right. Then it will be so marked.

MS. KELLS: Thank you.

(Confidential Wilson DEP Cross Examination Exhibit Number 2 was marked for identification.)

Q. Ms. Wilson, do you have the exhibit?

A. I do, yes.

Q. And would you agree this is a portion of the Company's response -- well, I guess we'll walk through it. So I'll represent to you this is a portion of the Company's response to Sierra Club Data Request 2-5, and the first page is just a cover page, and then this next page has the question and narrative response.

Would you agree that the first question, so part A, asks the Company to produce any unit replacement studies conducted by the Company; do you see that?

A. I do, yes.

Q. And then a confidential response. The response, itself, provides -- or refers to two attachments that are filed in response, and one of them is -- there's a long name, but it's basically called the 2016 Mayo retirement analysis; do you see that?

A. Yes, I do.

Q. And then starting on the fourth page through the end, there's a series of many tables. And I'll represent to you that that document, starting at page 4, is what is referred to as the 2016 Mayo analysis referenced in the response.

Do you see that part of the exhibit?

A. Yes, I do.

Q. Did you review this data response prior to filing your testimony in this case?

A. I did look at it, yes.

Q. And would you agree that this document, the one with the tables, shows that, in 2016, the Company looked at the costs and benefits of retiring Mayo station earlier than was planned at the time?

A. Earlier than the depreciation date that was on the books, yes.

Q. And in preparing for your testimony and analysis, did you do an analysis of whether it would have been feasible or cost-effective for the Company to retire Mayo or Roxboro, rather than make the investments they're seeking -- we're seeking to recover here?

A. I did not look at -- my analysis is not a replacement analysis, no, so I did not do the type of analysis that Duke presents here in this document.

Q. Thank you, Ms. Wilson.

MS. KELLS: Commissioner, those are all the questions I have.

COMMISSIONER CLODFELTER: All right. Let me ask, are there any other parties who I don't show on my list but desire cross examination of Ms. Wilson?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, Ms. Lee, we're back to you on redirect.

MS. LEE: Thank you, Commissioner Clodfelter.

REDIRECT EXAMINATION BY MS. LEE:

Q. Just one quick clarification -- and forgive me, this might have just been my mishearing. I think it was the second question Ms. Kells asked you, Ms. Wilson, and she asked paraphrasing, making that recommendation, did your -- did you test -- did you test whether there was specific projects.

And I think your answer was something along the lines of no, it included all the units that were operating economically. Did you mean to say uneconomically there? Or did I mishear you? You may have said uneconomically?

A. I thought I did say uneconomically, but we'll have to go back to the transcript.

Q. Okay.

A. If I did not, then I believe that I meant to, yes.

Q. Okay. That's a good clarification. Thank you.

MS. LEE: Nothing further, Commissioner.

COMMISSIONER CLODFELTER: We'll see if any of the Commissioners have questions for Ms. Wilson, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Thank you. No, I have no questions.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: I have no questions.

COMMISSIONER CLODFELTER: Thank you. Chair Mitchell?

CHAIR MITCHELL: No questions for the witness.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions for

the witness, but I thank Ms. Lee for that clarification.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: Just one quick one.

EXAMINATION BY COMMISSIONER HUGHES:

Q. Ms. Wilson, you -- in your testimony, you do explain what you've seen in other states related to decision-making and integrating analysis into decision-making. I couldn't tell from your testimony whether the type of analysis that you did -- just looking at the net energy value, I think that's the way you're referring to it -- are you aware of any jurisdictions that have used that analysis as the principal analysis for making decisions?

A. I wouldn't say that it's the principal analysis. I would say that it's a first-stage analysis. And I think that utilities first take a look at ongoing operational costs and revenues when making a determination about coal unit economics, and they would take the result of that analysis and move into a second phase where we look at the type of replacement study that we've discussed here.

So, you know, this is certainly, I would say, a first step in the utility decision-making process, and there are other steps that would then determine whether or not it is in the best interest of ratepayers to retire one or more coal units along a specified retirement schedule that would be a -- it would represent a portfolio that is be more of a least-cost resource portfolio.

Q. Okay. That's all. Thank you.

A. Thank you.

COMMISSIONER CLODFELTER: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. Thank you. And, Ms. Wilson, I have no questions for you, so I believe we are at the point where we will entertain motions.

MS. KELLS: Commissioner, I would ask that Confidential Wilson DEP Cross Examination Exhibit Number 2 be moved into evidence. But actually, I don't have any questions on Commissioners' questions. I don't know if you said that.

COMMISSIONER CLODFELTER: My apologies.

We did have a question from Commissioner Hughes. Thank you for catching me this morning. It's been a long morning already, actually, so -- and Ms. Lee knows that. So you are correct, Ms. Kells. No questions on Commissioners' questions?

MS. KELLS: I don't have any.

COMMISSIONER CLODFELTER: Ms. Lee?

MS. LEE: I don't have any either.

COMMISSIONER CLODFELTER: Any other party?

(No response.)

COMMISSIONER CLODFELTER: Thank you for catching me. All right. Now we're back to motions.

MS. KELLS: Okay. Just to be -- so I'll do it again just to be clear. So I now move that Confidential Wilson DEP Cross Examination Exhibit Number 2 be moved into evidence at this time.

COMMISSIONER CLODFELTER: Hearing no objection, it will be so ordered.

MS. KELLS: Thank you.

(Confidential Wilson DEP Cross Examination Exhibit Number 2 was admitted into evidence.)

COMMISSIONER CLODFELTER: And, Ms. Lee, I think we got your exhibits.

MS. LEE: Yes. If we could please move Sierra Club Wilson Exhibits 1, 4, and 5, and Confidential Sierra Club Wilson Exhibit 2 and 3 into evidence.

COMMISSIONER CLODFELTER: Without objection, they are admitted into evidence.

(Sierra Club Wilson Exhibits 1, 4, and 5, and Confidential Sierra Club Wilson Exhibits 2 and 3 were admitted into evidence.)

MS. LEE: And we would also please request that the witness now be excused.

COMMISSIONER CLODFELTER: Unless some party has an objection to excusing Ms. Wilson, she is excused. Thank you, Ms. Wilson, for being with us.

THE WITNESS: Thank you very much.

COMMISSIONER CLODFELTER: Anything else, Sierra Club?

MS. LEE: No, sir. Thank you.

COMMISSIONER CLODFELTER: Okay. Mr. Quinn, I hope you're awake. I can't see you on my screen. At this point, Ms. Downey, before we go into the Public Staff's case, as I indicated earlier, what I propose to do is to just be sure that we don't have any other intervenors in the case who presented testimony that they need to move into the record at this point.

Let me say that, if the testimony was already moved into the record and admitted into the record in the joint phase of the case, you don't need to move it again. That is copied into the transcript as we discussed in the opening statement in this proceeding.

If your testimony was offered only in the Duke Energy Carolinas case and was not to be offered in this case, then you do not need to move it. If, though, you have testimony that needs to be offered in this case and was not previously admitted into evidence in the consolidated hearing, then that's what we'll take now.

And I'm just going to go down the list of the party intervenors that I have whose evidence we've not already taken. And as I say, I can't see everyone on my screen, so I'm not sure who's appearing this morning for the parties. I'm just going to call the intervenor's name, and if you'll flag me down and let me know who you are.

Vote Solar?

MR. CULLEY: Good morning, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Good morning, Mr. Culley, I didn't have you on my screen. Any motions you need to make at this point?

MS. CULLEY: I believe we should be taken care of with your instructions at the beginning of the hearing, as our consolidated -- our testimony was admitted during the consolidated portions and would be copied at the appropriate time.

COMMISSIONER CLODFELTER: That's correct. And for such witnesses, as you'll recall from the opening statement who presented evidence in the consolidated hearing but not evidence in this proceeding, their testimony from the consolidated record is transcribed in at the beginning of the intervenors' cases in this case. So you are good to go, Mr. Culley.

MS. CULLEY: Thank you.

(Exhibits JMV-TF-1 through JMV-TF-7 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct testimony of James Van Nostrand and Tyler Fitch was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

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

In the Matter of	**)**
Application of Duke Energy Progress, LLC	**)**
For Adjustment of Rates and Charges	**)**
Applicable to Electric Service	**)**
In North Carolina	**)**

DIRECT TESTIMONY OF

JAMES VAN NOSTRAND

AND

TYLER FITCH

ON BEHALF OF
VOTE SOLAR

APRIL 13, 2020

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

* * * * *

TABLE OF CONTENTS

LIST OF ATTACHMENTS

1. INTRODUCTION

A. JAMES M. VAN NOSTRAND

Q. Please state your name, title and employer.

A. My name is James M. Van Nostrand. I am an Energy Policy Expert for EQ Research, a consulting firm based out of Cary, North Carolina. I am also a Professor of Law at the West Virginia University College of Law, where I teach energy and environmental law and Direct the Center for Energy and Sustainable Development.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. Exhibit JMV-TF-1 sets forth my educational background and professional experience.

B. TYLER FITCH

Q. Please state your name, title, and employer.

A. My name is Tyler Fitch. I am Southeast Regulatory Manager for Vote Solar.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. Exhibit JMV-TF-2 sets forth my educational background and professional experience.

C. OVERVIEW OF JOINT TESTIMONY

Q. Does each sponsoring witness adopt the whole of this testimony?

A. Yes. However, Mr. Fitch is not a lawyer and defers to Mr. Van Nostrand regarding any portion of this testimony that could be perceived as requiring legal training to answer.

Q. Please summarize your testimony.

A. This testimony focuses on the Grid Improvement Plan proposed by Duke Energy Progress ("the Company") and its request to recover the costs of the Plan through deferral to a regulatory asset. In particular, our testimony examines the extent to which the Company has integrated the impact of climate change-related risks in its Grid Improvement Plan. Since 2017, risks related to climate change have emerged as a material factor in electric utility operations. Recent developments in climate risk assessment, scrutiny from shareholders, and regulatory momentum underscore the need to manage these risks. Given the exposure faced by the Company to climate change-related risks due to, among other things, the vulnerability of its physical assets to more frequent and intense extreme weather events as well as the impact of increasing temperatures on its system, prudent utility practice requires that these risks be considered as part of any long-term plan for transmission and distribution investments. Our testimony concludes that the Company's analysis of climate change-related risks in connection with its Grid Improvement Plan is woefully inadequate, and the Company likely has fallen short of sustaining its burden of proof to demonstrate that the proposed expenditures associated with the Plan are necessary and reasonable. Our testimony concludes with several recommendations to improve the integration of climate change-related risks in the

Company's long-term system planning, as well as a possible regulatory mechanism that would provide incentives for implementation of these recommendations.

Our testimony reaches the following conclusions:

- Climate-related risks, emerging in many vectors, have a material and substantial bearing on the Company's operations today and will continue to affect operations in the future. Collaborative processes in North Carolina are currently underway to assess these risks and their implications for the electric grid.
- The Company faces demonstrable physical risks from climate change and increasing scrutiny on climate risk management from relevant financial institutions.
- As a potential foundational investment for the 21st century grid, any grid modernization plan should consider best climate resilience practices alongside grid modernization best practices. This includes the fair assessment of distributed energy resources as climate resilience and grid modernization solutions.
- The Grid Improvement Plan, as filed, does not assess or respond to climate-related risks, nor does it adhere to grid modernization best practices. As a result, the Company's proposal does not provide enough information to indicate that the Plan is a prudent investment.

Our testimony includes the following recommendations:

- The North Carolina Utilities Commission ("the Commission") should direct the Company to assess and manage climate-related risks across its operations and assets, in accordance with prudent utility practice.
- The Commission should make clear that it will hold the Company accountable for applying this standard to Grid Improvement Plan investments by the Company.
- The Commission should direct the Company to participate in ongoing Department of Environmental Quality stakeholder processes around grid modernization and integrate data, findings, and recommendations into its grid modernization investments. The Commission should further require that the Company file a report by December 31, 2020 identifying any gaps in knowledge that need to be filled through further collaboration.
- The Commission should require the Company to develop large distribution investments such as the Grid Improvement Plan through an integrated distribution planning ("IDP") or integrated systems & operations planning ("ISOP") process moving forward.
- To the extent that Grid Improvement Plan projects are authorized for deferred accounting, the Commission should impose performance-based conditions on the recovery of such deferred amounts in rates, such as through adjustments to the weighted average cost of capital applied to the unamortized balance of deferred amounts.

Q. How is your testimony organized?

A. The testimony is presented in several sections:

- **Section 2** provides context for the Grid Improvement Plan based on the Company's recent Power/Forward proposal, grid modernization best practices, and the response of the Commission. It also describes Vote Solar's experience as a stakeholder in the Company's Grid Improvement Plan stakeholder process.
- **Section 3** introduces the concept of climate-related risks, and demonstrates the extent to which such risks are at play in the Company's application. Section 3 includes a comprehensive review of the Company's exposure to such risks and best practices for managing them.
- **Section 4** identifies several policy and regulatory developments in North Carolina that may have bearing on any grid modernization process.
- **Section 5** presents a review of the Grid Improvement Plan's development based on grid modernization and climate resilience best practices as well as ongoing North Carolina developments.
- **Section 6** offers a specific discussion of the Company's request for deferred accounting, integrated systems planning, and the role of climate-related risks at the Commission.
- **Section 7** briefly discusses how the Company's customers would benefit from the integration of climate-related risks in long-term system planning.
- **Section 8** provides our conclusions and recommendations to the Commission.

2. POWER/FORWARD, STAKEHOLDER ENGAGEMENT, AND THE DEVELOPMENT OF THE GRID IMPROVEMENT PLAN

Q. Does the Grid Improvement Plan represent the Company's first proposed comprehensive investment plan for its transmission and distribution infrastructure?

A. No. The Company proposed the Power/Forward program in its last rate case.

Q. What was Power/Forward?

A. Power/Forward was a 10-year, $13 billion grid modernization plan for the Duke Energy Carolinas and Duke Energy Progress transmission and distribution system proposed in the Company's 2017 General Rate Case.[1] Like the Grid Improvement Plan, the stated goals of Power/Forward included improving reliability and integrating distributed resources.[2] Although no extraordinary regulatory treatment was sought in the Duke Energy Progress case, the subsequent Duke Energy Carolinas General Rate Case proposed a Grid Reliability and Resiliency Rider or deferral into a regulatory asset for recovering Power/Forward costs.[3]

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[1] Direct Testimony of David B. Fountain on behalf of Duke Energy Progress, Docket No. E-2, Sub 1142. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=2e602d93-a288-4a6f-8c7c-d8684a747d91.

[2] Direct Testimony of Robert M. Simpson III on behalf of Duke Energy Progress, Docket No. E-2, Sub 1142. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=2e602d93-a288-4a6f-8c7c-d8684a747d91.

[3] Direct Testimony of Jane L. McManeus on behalf of Duke Energy Carolinas, Docket No. E-7, Sub 1146. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4701a724-c7aa-4ff0-bc30-1da295d6f57f.

Q. What was Vote Solar's role in that proceeding?

A. Vote Solar's then Regulatory Director, Dr. Caroline Golin, testified on behalf of the North Carolina Sustainable Energy Association in both the Duke Energy Carolinas and Duke Energy Progress proceedings. Her testimony assessed the appropriate treatment of a capital-intensive proposal, the prudency of the Power/Forward program (according to the program's overall cost-effectiveness) and its satisfaction of grid modernization best practices, namely:

- Clear and Measurable Goals
- Stakeholder Engagement
- Integrated Distribution Planning
- Cost/Benefit Analysis[4]

Dr. Golin's assessment found that Power/Forward was not justified on an economic or engineering basis and that it failed to implement any of the grid modernization best practices listed above. In the Duke Energy Carolinas rate case, Dr. Golin recommended that the Commission deny Duke Energy Carolinas's proposal and proactively establish a separate proceeding for a stakeholder-driven, staff-facilitated process for evaluating grid modernization investments.[5]

[4] Direct Testimony of Caroline Golin on Behalf of North Carolina Sustainable Energy Association ("NCSEA"), Docket No. E-2, Sub 1142. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4dc8a933-d7c8-4ace-b9ab-e53b8e5690d5.

[5] Direct Testimony of Caroline Golin on Behalf of NCSEA, Docket No. E-7, Sub 1146. Retrieved at https://votesolar.org/files/2215/1741/2799/Direct_Testimony_of_Caroline_Golin_2.pdf.

Q. Do you agree with Dr. Golin's identification of best practices and establishment of a separate proceeding for grid modernization programs?

A. We do. These best practices are supported by grid modernization experts who have presented them across the Southeast and across the country.[6]

Q. What did the Commission find in its decision on the Power/Forward proposal?

A. The Company did not seek recovery of investments relating to Power/Forward in the previous rate case, but the Commission nevertheless found that "[b]ased on the full record in this docket, the Commission concludes, however, that the Company has not yet provided compelling evidence that the proposed grid investment plan will result in meaningful benefits to ratepayers despite its cost."[7] The Commission noted that it would reconsider the proposal after an agreed-upon technical workshop and the outcome in Duke Energy Carolinas's general rate case proceeding.[8]

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[6] Alvarez, P., & Stephens, D., (2019, January). Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. *GridLab*. Retrieved at http://gridlab.org/wp-content/uploads/2019/04/GridLab_SC_GridMod.pdf;
Aggarwal, S., & O'Boyle, M., (2017, February). Getting the Most out of Grid Modernization. Energy Innovation. Retrieved at http://ipu.msu.edu/wp-content/uploads/2018/01/Grid-Modernization-Metrics-and-Outcomes-2017.pdf;
Migden-Ostrander, J., & Hauser, S., (2018, September). Grid Modernization and New Utility Business Model. *Regulatory Assistance Project & GridWise Alliance*. Presentation given to Clean Energy Legislative Academy. Retrieved at https://www.raponline.org/wp-content/uploads/2018/09/rap_migden_cnee_legislator_academy_2018_sep_11.pdf;
Migden-Ostrander, J., Littell, D., Shipley, J., Kadoch, C., Sliger, J., (2018, February). Recommendations for Ohio's Power Forward Inquiry. *Regulatory Assistance Project*. Retrieved at https://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february-final2.pdf.

[7] Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 et al. p. 99. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d2b2a1a0-dae1-45de-af9c-c987d4aeddc8.

[8] *Ibid.* p. 100.

In the Duke Energy Carolinas Rate Case, the Commission noted that, given that the Duke Energy Carolinas controls the timing of the investments and that regulatory lag has not been an issue for these types of investments in the past, a rider would be inappropriate for grid investments.[9] Further, the Commission found that the reasons cited by Duke Energy Carolinas to justify the Program do not qualify as extraordinary:

> "The Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, and aging assets are all issues the Company… [has] to confront in the normal course of providing electric service. The Commission further finds that … a number of the Power Forward programs and projects … are the kinds of activities in which the Company engages or should engage on a routine and continuous basis. Therefore, the Commission must conclude that Power Forward costs are not appropriate to be considered for deferral accounting."[10]

While the Commission found arguments for a separate proceeding "compelling," it ultimately directed the Company to utilize existing dockets for grid modernization proposals, of which one (the "Smart Grid Technology Plan" docket) is no longer active. The Commission also directed the Duke Energy Carolinas to "engage and collaborate with stakeholders" to address issues raised in the proceeding.[11] In his testimony in this proceeding, Witness Oliver identifies the

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[9] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 et al. p. 142-145. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.
[10] *Ibid.,* p. 146.
[11] *Ibid.,* p. 149.

Commission's Order in the Duke Energy Carolinas Rate Case as relevant guidance for present grid improvement investments.[12]

Q. How did the Company engage and collaborate with stakeholders between the conclusion of the previous rate case and this one?

A. Since the last rate case, the Company held three in-person stakeholder workshops that were facilitated by a third party and conducted a series of webinars. Company Witness Oliver describes the objectives of the first stakeholder workshop as to "[d]evelop understanding of proposed investments; hear and explore stakeholder feedback; and support a collaborative process going forward."[13]

Q. In what capacity did Vote Solar participate in the Grid Improvement Plan stakeholder process?

A. Vote Solar participated in all three of the in-person stakeholder workshops held by the Company and observed several of the Company's webinars.

Q. What is Vote Solar's interest in the grid modernization broadly and the Grid Improvement Plan specifically?

A. As with Dr. Golin's previous testimony, Vote Solar's position is that decisions on how states pursue grid modernization represent critical opportunities for our electric grid. Done correctly, the modernization of the grid can enable a system where customers see economic benefits, distributed energy resources are evaluated fairly, innovative solutions have a chance to compete with traditional investments,

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[12] Direct Witness of Company Witness Jay W. Oliver ("Oliver Direct"), p. 41, ll. 20 to p. 42, l. 20.
[13] Oliver Direct, p. 43, ll. 11-13.

the grid's environmental impact is reduced, and energy service is more reliable and resilient to shocks and stressors. An unacceptable grid modernization proposal, on the other hand, could create more costs for customers than benefits, and could fail to deliver on promised benefits. As the onset of climate-related risks affects the risk profile for many grid stakeholders, the need to get grid modernization right is even more urgent. Vote Solar participated in the stakeholder process in pursuit of a grid modernization process in North Carolina that adheres to the best practices cited in Dr. Golin's testimony and ultimately one that works toward a more dynamic, resilient, and distributed grid.

Q. Mr. Fitch, please characterize your experience as a stakeholder in this collaboration process.

A. I will characterize my direct experience as an in-person stakeholder in the third workshop and webinars, and base my review of the first and second workshop on pre-read packets and workshop readout reports provided as exhibits in this proceeding by Witness Oliver. I found the stakeholder workshops valuable insofar as they clarified the Company's justification of its proposal and provided an opportunity for stakeholders to share perspectives and goals for a grid modernization process. I cannot characterize the workshops as "collaborative" in the true definitional sense of a process where stakeholders and the Company work together toward a shared goal.. In general, the prevailing feeling among stakeholders during workshops was unidirectional information-sharing by the Company. Stakeholders did not appear to play a role in choosing which investments should be selected, or shaping the process by which the Grid Improvement Plan was developed.

Relatedly, I was surprised to find that the Company invited stakeholder input only after the Company had developed the Grid Improvement Plan.[14] This approach leaves stakeholders out of the most important elements of the grid modernization process—defining a shared set of goals and criteria for success, identifying possible solutions, and developing a process for selecting those solutions. In effect, the Plan was "already baked" by the time stakeholders were given a chance to share ideas.

This procedural element may be a reason that management of climate-related risks—an element that several stakeholders called for—was not included in the Plan.[15] The Company in fact explicitly stated that it intended to avoid the term "climate change," and the topic would be addressed only to the extent climate change risks were captured as part of the megatrend identified as "Environmental Trends" and "Impact of Weather Events." [16]

Q. Mr. Fitch, is it clear the extent to which differences between programs proposed in the Power/Forward and the Grid Improvement Plan were driven by stakeholder input?

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[14] Oliver Direct, p. 29, l. 18 to p. 30, l. 18.
[15] Oliver Direct Ex. 13, p. 12.
[16] Oliver Direct, Ex. 13, p. 29.

A. No. Witness Oliver represents that the stakeholder process led to the Company's creation of the Megatrends,[17] but the excerpt of the Commission's 2018 order cited above shows that several of these Megatrends were previously used to justify the Power/Forward plan. In any case, the Plan's similarity to Power/Forward (further discussed below) suggest that the Megatrends were a *post hoc* justification developed by the Company to justify the path it had already decided to pursue.

Company Witness Oliver cites several other changes to the plan as stakeholder-driven,[18] but a review of the workshop readout demonstrates more nuance at play: Targeted undergrounding was reduced, but the workshop readout report described this project as changing "priority";[19] and the distribution hardening & resiliency program was reduced in size, but the term "distribution hardening" does not appear in the workshop readout report.[20]

Q. Based on the workshop readout reports, what were other stakeholders' responses to the stakeholder process?

A. The Company rolled out its Grid Improvement Plan proposal at the second stakeholder workshop in November 2018. The readout report registers that stakeholders had a mixed, at best, view of the Plan, as shown in Figure 1. Key takeaways from the workshop included a note that stakeholders asked the Company

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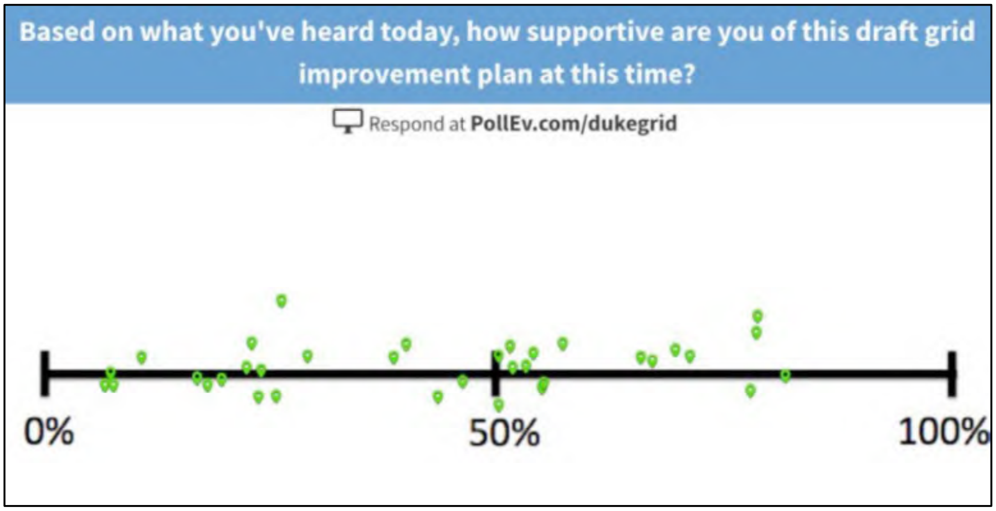
[17] Oliver Direct, p. 43, ll. 19-20.
[18] Oliver Direct, p. 43, ll. 20-22.
[19] Oliver Direct, Exhibit 11, p. 12-13.
[20] *Ibid.,* p. 1-44.

to explicitly include climate change as a megatrend and to better understand the DER-enablement implications of its proposal.[21]

Figure 1. Stakeholder Sentiment of Grid Improvement Plan.[22]



The third stakeholder workshop represented more of a "deep dive" into the cost-benefit methodology of several proposed programs, presented in the context of the Company's stated intention to file a rate case application including a Grid Improvement Plan in the next several months.[23] At the last workshop before the Plan's submission to the Commission, the role of stakeholder input was still unclear to stakeholders:

> "Several stakeholders felt unclear about the impact from current stakeholder engagement, and if/how stakeholder input has and will be meaningfully used in the GIP riling. In response, many stakeholders requested to see evidence

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[21] Oliver Direct, Ex. 13, p. 12.
[22] Figure is directly taken from Oliver Direct, Ex. 13, p. 22.
[23] Oliver Direct, Ex. 16, p. 6: "Several stakeholders were skeptical about how a "clean slate" for stakeholder engagement could be realized after the filing this year."

> and/or explicit explanations demonstrating how stakeholder feedback has thus far been incorporated."[24]

Of course, stakeholders at the Grid Improvement Plan workshops showed a wide range of opinions and interests, and the summary above is not meant to be comprehensive. It does, however, point to a trend of stakeholders (Vote Solar included) finding that the process did not meaningfully incorporate stakeholder input into proposed investments.

Q. Mr. Fitch, did the stakeholder process the Company conducted in advance of this rate case adhere to stakeholder best practices or a reasonable expectation of engagement and collaboration?

A. No. The stakeholder process did not allow stakeholders to set goals for the Plan or work with the Company to identify criteria for evaluating solutions. Especially for the third workshop, stakeholder input was unlikely to alter the Company's proposal to the Commission. Although the Company to my knowledge has not committed to a cyclical, ongoing stakeholder process, the potential for that type of process through the Company's proposed phases is possible. Overall, however, the stakeholder process did not adhere to these best practices.

[24] Oliver Direct, Ex. 16., p. 5-6.

Q. Please compare the Company's proposed Grid Improvement Plan to its previous Power/Forward plan.

A. The Company provided a comparison between the Grid Improvement Plan and Power/Forward during its April 2019 webinar,[25] and provided a more precise comparison between the programs in discovery.[26] Every program that made up Power/Forward is replicated in the Grid Improvement Plan, although the total budgets for targeted undergrounding and "incremental distribution hardening & resilience" have decreased substantially. Several new programs populate the GIP, including security measures, Integrated Volt-Var Control ("IVVC"), integrated systems & operations planning, and support for energy storage and EVs. Even so, over 80 percent of the capital investment that comprises the Grid Investment Plan is derived from projects that were also a part of Power/Forward.[27] The Grid Improvement Plan thus largely incorporates the same projects included in Power/Forward, although the Grid Improvement Plan's scope is much smaller than Power/Forward's (3 years versus 10 years). At the same time, however, it should be noted that the Company has described at least one more "phase" of the Grid Improvement Plan.[28]

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[25] Oliver Direct, Ex. 14 p. 10.
[26] Company Response to Vote Solar Data Request -1-2.
[27] *Ibid.* Investment in SOG, Incremental Transmission H&R, Transmission Bank Replacement, Oil Breaker Replacement, T&D Communications, Distribution System Automation, Transmission System Intelligence, and T&D Enterprise systems totals $1.952 billion, which is ~84% of the $2.3 billion budget.
[28] Oliver Direct, p. 47, ll. 9 to p. 48, ll. 18.

Q. Mr. Fitch, how did the Company portray its Integrated Systems & Operations Planning ("ISOP") project in Company meetings and webinars?

A. ISOP presentations[29] portrayed ISOP as a way to integrate planning processes across generation, transmission, distribution, and customer services,[30] and identified capabilities of the Advanced Distribution Planning component of ISOP to include "optimized selection of both traditional and non-traditional solutions."[31]

Q. What appears to be the relationship between ISOP and the Grid Improvement Plan?

A. ISOP is an identified component of the Grid Improvement Plan. It is not apparent from the Company's materials how the Grid Improvement Plan projects will be sequenced in their implementation, despite the clear value that the capabilities of ISOP, ADP, and Morecast would bring toward identifying grid needs and placing solutions.

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[29] Mr. Fitch reviewed Duke Energy's presentation of ISOP to the Commission on August 28, 2019, and observed the ISOP webinar on January 30, 2020.

[30] Duke Energy (2019, August), Integrated Systems & Operations Planning (ISOP) Technical Conference. *North Carolina Utilities Commission*, p. 5. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/isop/isop-ncuc-conference-overview-rev0.pdf?la=en.

[31] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (2019, August). Response to Commission Questions in July 23, 2019 Order Docket No. E-100, Sub 157. Retrieved at https://www.duke-energy.com/_/media/pdfs/our-company/isop/e100-sub157-decdep-response-to-ncuc-questions.pdf?la=en.

3. ONSET OF CLIMATE-RELATED RISK AND FUNDAMENTAL CHANGES IN THE ELECTRIC UTILITY SECTOR

A. Introducing Climate-Related Risks

Q. Why is climate change relevant to the Company's general rate case application?

A. In its response to Vote Solar's motion to compel responses to discovery in the Duke Energy Carolinas Rate Case, the Duke Energy Carolinas acknowledged that the words climate change or global warming do not appear in its application,[32] and posited that the scope of this proceeding is "limited to the costs, revenues, rates, and regulatory mechanisms reflected in its application."[33] We agree that the focus of this proceeding should not be about climate change, but there is no question that climate-related risks clearly influence the costs, revenues, rates, and regulatory mechanisms in DEC's application. The same statements apply to the Company's application in this proceeding. Whether or not the Company explicitly uses the term "climate-related" or "climate change" in its application, the physical impacts of climate change and the financial, regulatory, and societal responses to it have real, material implications for the Company and the prudency of current proposals in its Application. The following items in the Company's application have climate-related risk implications:

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[32] Duke Energy Carolinas, LLC's Response to Opposition to Motion to Compel Discovery, Docket No. E-7, Sub 1146, p. 2.
[33] *Ibid.* p. 4.

- The Grid Improvement Plan. The Plan purports to "mitigate the impact of major storm events,"[34] and "support more rooftop solar, battery storage, electric vehicles, and microgrids."[35] Storm and flood risks are likely to change due to climate change,[36] and Executive Order 80[37] and the Clean Energy Plan,[38] both of which cite climate-related risks as a driver, urge adoption of policies that are intended to increase customers' use of rooftop solar, battery storage, electric vehicles and microgrids.

- Storm costs from Hurricanes Florence and Michael and Winter Storm Diego.[39] The frequency and intensity of those storms is increasing, which the Company acknowledges.[40] But if the Company does not update storm preparation to account for this reality there will be implications for the Company's assets[41] and the ability of its customers to cope with the impacts of those storms.[42] Given the Brunswick nuclear plant's exposure to floods as during Hurricane Florence,[43] there is reason to be particularly attentive to this concern.

- Investments to upgrade Company assets to reduce carbon emissions.[44] Switching to lower-carbon fuels reduces regulatory climate-related risk in the future. The application notes this fact when it explains that the

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[34] Duke Energy Progress, LLC Application to Adjust Retail Rates, Request for an Accounting Order, and to Consolidate Dockets ("DEP Application"). p. 10.
[35] *Ibid.*
[36] Kunkel, K., & Easterling, D., (2020, January). North Carolina Climate Science Report. Presentation given to North Carolina Climate Change Interagency Council, p. 28. Retrieved at https://files.nc.gov/ncdeq/climate-change/interagency-council/Jan-22-2020--Interagency-Climate-Council-presentation-rev.pdf.
[37] State of North Carolina Exec. Order No. 80, (2018, October).
[38] North Carolina Department of Environmental Quality, (2019, October), North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System. Retrieved at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.
[39] DEP Application, p. 5.
[40] *Ibid.* p. 10.
[41] Morehouse, C., (2020, January), "Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's." *Utility Dive.* Retrieved at https://www.utilitydive.com/news/ameren-xcel-dominion-duke-among-most-at-risk-from-changing-climate-mood/570789/.
[42] ConEdison (2019, December). Climate Change Vulnerability Study. p. 31. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[43] Murawski, J., (2018, September). "Floods limit access to Duke's Brunswick nuclear plant; crews use porta-potties, cots." *The News & Observer.* Retrieved at: https://www.newsobserver.com/news/local/article218530735.html.
[44] DEP Application, p. 5, #9.

investments will "further reduce carbon emissions across the Carolinas for the benefit of customers."[45]

- Accelerated depreciation for coal assets.[46] Again, this acts as a hedge against potential climate regulation, and the application and Witness DeMay argue that investing in cleaner energy sources is done "for the benefit of [the Company's] customers."[47,48]

- The Company's return on equity.[49] Witness Hevert does not mention that Moody's credit opinions for the Company in 2019 mention its "carbon transition risk,"[50] thereby failing to capture a recent significant pivot in how the financial industry views climate-related risks.

These items show that the Company's decisions today are influenced by climate-related risks and affect the Company's future exposure to those risks. This is not an exhaustive list of climate-related risks to the Company; climate-related risks operate through multiple vectors beyond physical impacts and are complex and inter-related. Avoidance of, or, conversely, engagement with, these risks is very likely to impact the Company's operations and financial position, as we discuss below.

In response to discovery on how it manages climate-related risks, the Company states that "[it], as well as its stakeholders, are unable to say with certainty what the future impacts of climate change may or may not be."[51] This is neither a responsible nor a mainstream approach to risk management. As expressed

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[45] *Ibid.*
[46] *Ibid.* p. 8.
[47] *Ibid.* p. 9.
[48] Direct Testimony of Company Witness Stephen G. De May ("De May Direct"), p. 14, l. 14
[49] DEP Application. p. 14.
[50] Company Response to Vote Solar Data Request 1-24.
[51] Company Response to Vote Solar Data Request 1-12,.

by State Street CEO Ronald O'Hanley in his recent statement to the *Wall Street Journal* on climate-related risks:

> "Does anyone know with certainty or precision what the scope and pace of climate change might mean for long-term investments? No. But that is the textbook definition of risk: More things can happen than will happen."[52]

As in any business, risk management is fundamental to prudent business practice. As we demonstrate, the Company and Commission are better equipped than ever before to consider the material risks associated with climate change.

Q. What are climate-related risks?

A. Climate-related risks refer to the potential negative impacts of climate change on a firm or organization. Risks may emerge as a result of the physical shocks and stresses of climate change (physical risks), or the social and economic response to those impacts (transition risks). Importantly, the risks discussed here are those borne by the firm alone, not by its customers or society as a whole. As such, the climate-related risks described here are no different than any other business risk that a firm might assess and manage in the course of prudent operation.

Due to the carbon emissions embedded in conventional electricity generation and the nature of transmission and distribution infrastructure, electric

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[52] O'Hanley, R., (2020, January). Sustainability Is Part of Good Risk Assessment. *Wall Street Journal*. Retrieved at https://www.wsj.com/articles/sustainability-is-part-of-good-risk-assessment-11580413295#comments_sector.

utilities are among the most vulnerable industries to climate-related risk.[53] Climate-related risks that electric utilities face are categorized below:

- **Physical:** Impacts to assets and operations from physical climate impacts.
- **Financial:** Impacts to cost-of-capital due to climate-related exposure and confidence in risk management.
- **Economic:** Risk of stranded assets or decreased sales due to increased viability of alternatives.
- **Regulatory:** Impacts to operating and capital costs from changing regulations.
- **Reputational:** Potential loss of goodwill due to perceived response to climate change.

Although these categories may be helpful for identifying different types of risk, it should be noted that climate-related risks are complex and interconnected.[54] It is therefore important to understand these risks as related to each other and specifically related to climate change.

For each dimension of risk, we summarize the mechanism by which it impacts utility operations, provide an overview of state-of-the-art efforts to characterize the risk, and describe the Company's potential exposure.

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[53] The Task Force on Climate-Related Disclosures identified the energy sector, including electric utilities, as one of four non-financial groups with "the highest likelihood of climate-related financial impacts." Task Force on Climate Related Financial Disclosures, (2017, June). Recommendations of the Task Force on Climate-Related Disclosures. P. 16. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf.
[54] *Ibid.,* p. 10.

Q. Does the broader business and financial community consider these risks material? Has the perception or assessment of these risks changed since the Company's last rate case?

A. The answer is "yes" to both questions. While climate change and its attendant business risks may be a lightning rod topic for some, Company witness DeMay observes—and we agree—that "[t]he energy sector is in a period of transformation and profound change," due to technological advancements, environmental mandates, notions of resiliency, and changing customer expectations.[55] Climate-related risks encapsulate these transformative changes, and the industry has reached a tipping point since the Company's last rate case application in 2017. Six key developments are driving this transformation:

First, a common framework for understanding, disclosing, and managing climate-related risks is emerging. At the request of the G20, the Financial Stability Board formed the Task Force on Climate-related Financial Disclosures ("TCFD") in 2015 to develop a universal framework for risk disclosure. The TCFD's final recommendations were published on June 15, 2017—six weeks after the Company submitted its application for the 2017 rate case.[56] Since then, TCFD's

[55] De May Direct, p. 5, ll. 18-21.
[56] Duke Energy Progress, LLC. Application to Adjust Retail Rates and Request for an Accounting Order. Docket No. E-2, Sub 1142. Retrieved at:https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7e497cdb-bbfb-491d-ba4c-d52764d37112.

recommendations have become the international standard, adopted by almost 800 organizations representing over $118 trillion in assets.[57]

Second, awareness of the here-and-now risks of climate change to electric utilities—and the urgent need to mitigate those risks—have materialized since 2017. The California wildfires and related PG&E bankruptcy and large-scale public service power shutoffs in response to fire risks have galvanized public conversation about the role of electric utilities in mitigating climate impacts.[58] One Wall Street Journal headline aptly summarizes the new orientation toward climate-related damages: "For the Economy, Climate Risks are No Longer Theoretical."[59]

Public and private institutions have responded to these impacts. Since 2017, seven US states made commitments to 100 percent renewable energy,[60] and eleven of the country's largest utility holding companies, including Duke Energy, have announced deep emissions reduction goals.[61] In section 4, we address the related developments in North Carolina policy, including Executive Order 80 and the

[57] Task Force on Climate-related Financial Disclosures, (2019, May). 2019 Status Report. pp. 2. Retrieved at https://www.fsb-tcfd.org/publications/tcfd-2019-status-report/.
[58] Gold, R., (2019, January), PG&E: The First Climate-Change Bankruptcy, Probably Not the Last. *Wall Street Journal.* Retrieved at https://www.wsj.com/articles/pg-e-wildfires-and-the-first-climate-change-bankruptcy-11547820006.
[59] Ip, G., (2019, January), For the Economy Climate Risks Are No Longer Theoretical. *Wall Street Journal.* Retrieved at https://www.wsj.com/articles/for-the-economy-climate-risks-are-no-longer-theoretical-11579174209.
[60] UCLA Luskin Center for Innovation, (2019, November), Progress Toward 100% Clean Energy in Cities & States Across the US. Retrieved at https://innovation.luskin.ucla.edu/wp-content/uploads/2019/11/100-Clean-Energy-Progress-Report-UCLA-2.pdf.
[61] Gearino, D., (2019, October), Utilities Are Promising Net Zero Carbon Emissions, But Don't Expect Big Changes Soon. *InsideClimateNews*. Retrieved at https://insideclimatenews.org/news/15102019/utilities-zero-emissions-plans-urgency-coal-gas-duke-dte-xcel.

Clean Energy Plan, which bring a similar awareness and anticipation of climate change's physical, social, and economic changes into this jurisdiction.

Third, major financial institutions are taking the onset of climate-related risks seriously. The U.S. Commodity Futures Trading Commission, understanding the implications of these risks, created a climate-related financial risk subcommittee to provide insights and recommendations to market regulators and participants.[62] Larry Fink, CEO of the world's largest asset manager BlackRock, recently addressed climate-related risks as the driver of a "fundamental re-shaping of finance" in his annual letter to global CEOs.[63] Fink's letter, and research from BlackRock's Investment Institute,[64] also contend that climate-risks are already present in utility stocks, but they haven't been adequately evaluated by investors. As those risks become clearer, Fink writes that "[i]n the near future—and sooner than most anticipate—there will be a significant re-allocation of capital."[65] BlackRock's position as one of the largest and most influential investors in the world lends credence to these claims. Notably, BlackRock is the 2nd largest individual shareholder in Duke Energy Corporation.

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[62] Litterman, R., (2019, December), Remarks to the Market Risk Advisory Committee. *U.S. Commodity Futures Trading Commission.* Retrieved at https://www.cftc.gov/media/3181/MRAC_Litterman121119/download.
[63] Fink, L., (2020, January), A Fundamental Reshaping of Finance. *BlackRock*. Retrieved at: https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter
[64] Bertolotti, A., Basu, D., Akallal, K., Deese, B., (2019, March), Climate Risk in the US Electric Utility Sector: A Case Study. *BlackRock Investment Institute*. Retrieved at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3347746.
[65] Fink, 2020.

Institutional investors see managing climate-related risks as part of their fiduciary duty to protect the long-term health of their investments. In February 2019, twenty of the world's largest institutional investors, representing over $1.8 trillion in assets, sent a letter to Duke Energy and other electric utilities indicating that "[a]s long-term investors, we view these [climate-related] risks as significant and material," and calling on firms to set a net-zero by 2050 goal over the next six months.[66] Duke Energy Corporation published its net-zero by 2050 goal seven months later, in September 2019.[67]

Fourth, analytical capability to understand climate risks at a granular level has improved dramatically in the last several years. Analysts are capable of projecting climate-related risks and impacts on a single-county level.[68] One recent study of electric utilities viewed risks on a generating plant-by-plant basis.[69] The credit rating agencies of Moody's and S&P are increasing their in-house analytical capacity on this front, and in January 2020 Moody's released its first comprehensive assessment of climate risk for electric utilities.[70]

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[66] California Public Employees Retirement System et al., (2019, February). *Institutional Investor Statement Regarding Decarbonization of Electric Utiltiies*. Retrieved at https://www.climatemajority.us/investorstatement-20190228.
[67] Duke Energy (2019, September). Duke Energy aims to achieve net-zero carbon emissions by 2050. Retrieved at https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.
[68] Larsen, K., Larsen, J., Delgado, M., Herndon, W., Mohan, S, (2017, January) Assessing the Effect of Rising Temperatures: The Cost of Climate Change to the U.S. Power Sector. Rhodium Group, p. 10-19. Retrieved at https://rhg.com/wp-content/uploads/2017/01/RHG_PowerSectorImpactsOfClimateChange_Jan2017-1.pdf.
[69] Bertolotti, et al. (2019).
[70] Morehouse, C. (2020, January). Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's. *Utility Dive.* Retrieved at: https://www.utilitydive.com/news/ameren-xcel-dominion-duke-among-most-at-risk-from-changing-climate-mood/570789/.

Fifth, state regulatory regimes are developing best practices for understanding vulnerability to climate-related risks and crafting specific implementation plans for addressing them. In North Carolina, Governor Roy Cooper's Executive Order 80 initiated a process that includes a comprehensive climate risk assessment, which was released to the public on March 11, 2020.[71] The executive summary of that assessment is provided as Exhibit JMV-TF-3. After Superstorm Sandy, the New York Public Service Commission convened a Grid Hardening & Resiliency Collaborative to reach consensus on risks to the Con Edison system and approaches to managing them—a move that has been hailed as a "nationwide model"[72] and an innovative approach[73] for managing climate-related risks. In partnership with the collaborative, Con Edison released its Climate Change Vulnerability Study in December 2019. This study represents a leap forward in the depth of analysis of climate-related risks, and the utility will develop an

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[71] North Carolina Institute for Climate Studies (2020, March). The North Carolina Science Report. Retrieved at: https://ncics.org/cics-news/the-north-carolina-climate-science-report/.
[72] Ralff-Douglas, K., (2016, June). Climate Adaptation in the Electric Sector: Vulnerability Assessments & Resiliency Plans. *California Public Utility Commission*, p. 5. Retrieved at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Climate%20Adaptation%20Plans.pdf.;
Case 13-E-0030 *et al.;* Con Edison's Electric, Gas, and Stream Rates -- Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (2014, February). State of New York Public Service Commission. Retrieved at: https://climate.law.columbia.edu/sites/default/files/content/docs/Final-Order-2014-02-21%20(1).pdf
[73] Columbia Law School, (2014, February). Center for Climate Change Law Helps Secure Novel Pact with Con Edison. Retrieved at: https://www.law.columbia.edu/media_inquiries/news_events/2014/february2014/Con-Ed-climate-change-measures.

implementation plan to address risks throughout 2020. A copy of the Climate Change Vulnerability Study is provided as Exhibit JMV-TF-4.

Sixth, analysts and investors are urging firms to take action in the short-term. The U.S. Global Change Research Project concludes that utilities are already subject to climate-related physical risks.[74] The United Nations Principles for Responsible Investment summarize the point succinctly: "Failure to consider all long-term investment value drivers, including [environmental, social, and governance] issues, is a failure of fiduciary duty."[75]

To recap, there is a common understanding of climate-related risks; investors and the public are taking these risks seriously; new analytical tools render climate risks understandable; a collaborative model for addressing risks exists; and there is value to a proactive approach. Recognition and management of these risks will transform how utilities undertake prudent planning and operations. These developments also mean that firms and regulators now have the tools to act.

Q. What materials have you reviewed in preparation of this testimony?

A. We reviewed literature from the following categories to inform this testimony:

- Duke Energy Progress and Duke Energy Corporation statements on climate change and climate-related risks;

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[74] Zamuda, C., et al. (2018). Energy Supply, Delivery, and Demand in *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*. U.S. Global Change Research Program, pp. 174-201. Doi: 10.7930/NCA4.2018.CH4.

[75] United Nations Principles of Responsible Investment (2019, November). Fiduciary Duty in the 21st Century Final Report. Retrieved at: https://www.unpri.org/fiduciary-duty-in-the-21st-century-final-report/4998.article#.Xc0f5YqtBhQ.twitter.

- Decisions by North Carolina policymakers that might inform future climate-related regulatory risk;
- Financial institution discussion and business decisions on climate-related risks;
- Guidance from financial advisory organizations on prudent business practice around disclosing and managing climate-related risks;
- Research assessing the nature of climate-related risks and best practices on avoiding them from top research organizations;
- Case studies of other electric utilities and utility commissions weighing their own response to climate-related risks.

In total, our review spanned 130 sources from 97 organizations. While the review presented here is not exhaustive or universal, the documents assembled paint a clear picture of the current state of recognizing climate-related risks and the institutional response to them. A list of sources consulted during the literature review is available in Exhibit JMV-TF-5.

B. Physical Risks

Q. Please define climate-related physical risks and describe how they are expected to impact the electric utility industry.

A. Climate-related physical risks are risks to assets or operations due to physical phenomena impacted by climate change. These physical changes can manifest as rising sea levels and flood risk, increasing ambient temperatures and heat waves, changing precipitation patterns, and/or increasing frequency and intensity of extreme weather events. Just as weather and climate have always affected the day-to-day operations and long-term planning of electric utilities, the industry is already affected by the changing climate at the generation, transmission, and distribution levels.[76]

Climate change impacts that will have the most substantial risk implications for the electric industry are listed below.

- **Extreme Weather Events:** More frequent and severe but less predictable storms (and, in coastal areas, attendant storm surges) will result in damage to infrastructure and increases in storm damages. Ratepayers are likely to see decreased reliability and the potential for long outages.[77]
- **Increased Temperatures:** Increased ambient temperatures will reduce performance and reliability of electricity infrastructure.[78] Customer demand is projected to increase as cooling loads increase, but become less predictable.[79] Longer, more intense heat waves present health risks for utility workers. High temperature and high cooling load will present sustained stress to the grid.[80]
- **Changes in Precipitation:** Although not necessarily applicable to the Company's service territory, projected precipitation patterns as a result of

[76] Zamuda, C., et al. (2018).
[77] McKinsey Global Institute (2020, January). Climate risk and response :Physical hazards and socioeconomic impacts. Retrieved at: https://www.mckinsey.com/business-functions/sustainability/our-insights/climate-risk-and-response-physical-hazards-and-socioeconomic-impacts.
[78] Bertolotti et al., p. 5.
[79] ConEdison (2019, December). Climate Change Vulnerability Study. p. 12. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[80] Larsen, K., Larsen, J., Delgado, M., Herndon, W., Mohan, S, (2017, January) Assessing the Effect of Rising Temperatures: The Cost of Climate Change to the U.S. Power Sector. Rhodium Group, p. 10-19. Retrieved at https://rhg.com/wp-content/uploads/2017/01/RHG_PowerSectorImpactsOfClimateChange_Jan2017-1.pdf.

climate change are likely to lead to drier conditions in the southern and western parts of the United States, with intermittent episodes of heavy precipitation.[81] A lack of steady water supply could severely impede the operation of nuclear and conventional thermal plants, which rely on an available stream of water for cooling.[82] Droughts may also increase the risk of wildfire, with clear and present implications for utilities' transmission and distribution.[83]

- **Sea-level Rise and Flooding:** Especially in combination with extreme weather events, higher sea levels increase the risk of inundation for coastal assets.[84]

While electricity infrastructure is designed to withstand a range of conditions, future conditions are projected to exceed historical ranges. Understanding and planning for future conditions, and not just relying on historical benchmarks, is becoming necessary to avoid premature asset replacement and stranded assets.[85]

Analysts estimate that these damages can be material in the case of electric utilities. In a review of the financial materiality of climate-related physical risks to electric utilities, BlackRock Investment Institute placed the increased frequency

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[81] Nanavati, P., & Gundlach, J., (2016, September), The Electric Grid and its Regulators—FERC and State Public Utility Commissions. Sabin Center for Climate Change Law at Columbia Law School, p. 14.
[82] *Ibid.,* p. 15.
[83] Bertolotti *et al.*, p. 4.
[84] Nanavati & Gundlach, pp. 19.
[85] Chung, J., (2020, January). *Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's* (interview by Catherine Morehouse for Utility Dive);
Kunkel, K., & Easterling, D., (2020, January). North Carolina Climate Science Report. Presentation given to North Carolina Climate Change Interagency Council, p. 33. Retrieved at https://files.nc.gov/ncdeq/climate-change/interagency-council/Jan-22-2020--Interagency-Climate-Council-presentation-rev.pdf

and severity of hurricanes as a "10" on a 1-10 scale.[86] Another estimate found that storm damages were, on average, likely to increase by 23 percent to $1.7 billion per year by 2050.[87] It is now possible to examine climate risks at the granularity of individual generating plants.[88]

Insurers are increasingly exposed to risks of increasing claims and payouts as the incidence of climate-related events grows.[89] After California's 2018 climate-related[90] wildfire season, which included over 13,000 homes and businesses destroyed and 46,000 insurance claims,[91] analysts were concerned that California utilities might be "uninsurable."[92]

Q. How will climate-related physical risks affect the Company specifically?

A. The Company's location in North Carolina largely determines its exposure to climate-related risks. Although all utilities will be subject to the risks above,

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[86] BlackRock, (2019, April), Getting Physical: Scenario Analysis for Assessing Climate-Related Risks. p.17. Retrieved at https://www.blackrock.com/us/individual/literature/whitepaper/bii-physical-climate-risks-april-2019.pdf.

[87] Brody, S., Rogers, M., Siccardo, G., (2019, April), Why, and how, utilities should start to manage climate-change risk. McKinsey & Company, p. 3. Retrieved at: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/why-and-how-utilities-should-start-to-manage-climate-change-risk.

[88] Bertolotti, et al.

[89] Flavelle, C. (2019, August). As Wildfires Get Worse, Insurers Pull Back from Riskiest Areas. *New York Times*. Retrieved at: https://www.nytimes.com/2019/08/20/climate/fire-insurance-renewal.html.

[90] Shrimali, G. (2019, October). In California, More than 340,000 Lose Wildfire Insurance. *High Country News*. Retrieved at https://www.hcn.org/articles/wildfire-in-california-more-than-340000-lose-wildfire-insurance.

[91] Bernstein, S., & Barlyn, S., (2019, January). Insurance losses for California Wildfires top $11.4 Billion. *Reuters*. Retrieved at https://www.reuters.com/article/us-california-fire-claims/insurance-losses-for-california-wildfires-top-114-billion-idUSKCN1PM2CF.

[92] Jaffe, A., Busby, J., Blackburn, J., Copeland, C., Law, S., Ogden, J., & Griffin, P., (2019, September). Impact of Climate Risk on the Energy System. *Council on Foreign Relations*. Retrieved at https://cdn.cfr.org/sites/default/files/report_pdf/Impact%20of%20Climate%20Risk%20on%20the%20Energy%20System_0.pdf.

Southeast utilities are particularly exposed to more frequent and severe storms and hurricanes.[93]

High-quality, in-depth studies of climate impacts focused specifically on North Carolina are in progress. As directed by Section 9 of Governor Roy Cooper's Executive Order 80, leading North Carolina institutions have released a North Carolina Climate Science Report that assesses the state of the science and makes projections for North Carolina-specific impacts.[94] Findings from the report indicate that, "[l]arge changes in North Carolina's climate—much larger than at any time in the state's history—are ***very likely*** by the end of this century under both the lower and higher [emissions] scenarios."[95] Authors of the report presenting to the North Carolina Climate Change Interagency Council found it is "***very likely*** [90-100% probability]" that NC temperatures will increase in all seasons, extreme precipitation frequency and intensity will increase, and that heavy precipitations accompanying hurricanes passing over North Carolina will increase.[96] As a result, climate design standards for North Carolina infrastructure will be outdated by the middle of this century[97]—likely within the design lifetime of investments proposed under the Grid Improvement Plan. The North Carolina Climate Science report was

[93] Zamuda, C., et al.
[94] North Carolina Department of Environmental Quality, (2019). NC Climate Science Report Development. Retrieved at https://deq.nc.gov/nc-climate-science-report-development.
[95] Kunkel, K., & Easterling, D., (2020, January), emphasis in original.
[96] *Ibid.,* emphasis in original.
[97] *Ibid.*

released to the public on March 11, 2020,[98] and its executive summary is attached as Exhibit JMV-TF-3. It is a key input into the North Carolina Climate Risk Assessment and Resiliency Plan, which is currently in development.

Financial observers have already been paying careful attention to utilities' climate-related physical risks. When S&P announced a negative outlook for Duke Energy Corporation in 2019, it noted that "[t]he company also operates its utilities in regions of the U.S. that are prone to frequent hurricanes, which could increase the company's risk exposure because climate change is intensifying the severity and frequency of these natural disasters globally."[99] Moody's and S&P mentioned hurricanes or named storms in ratings of the Company in each year 2017-2019.[100]

Beyond broad characterizations, credit rating agencies are using increasingly powerful analytical methods for understanding climate risks, finding that Duke Energy's footprint in the Carolinas in particular is exposed to climate-related risks. Moody's published its first review of climate-related risks for electric utilities in January 2020 and found Duke Energy a top risk for hurricane threats.[101]

Materials submitted by the Company in this proceeding validate the findings reported by Moody's. Figure 2 below disaggregates system average

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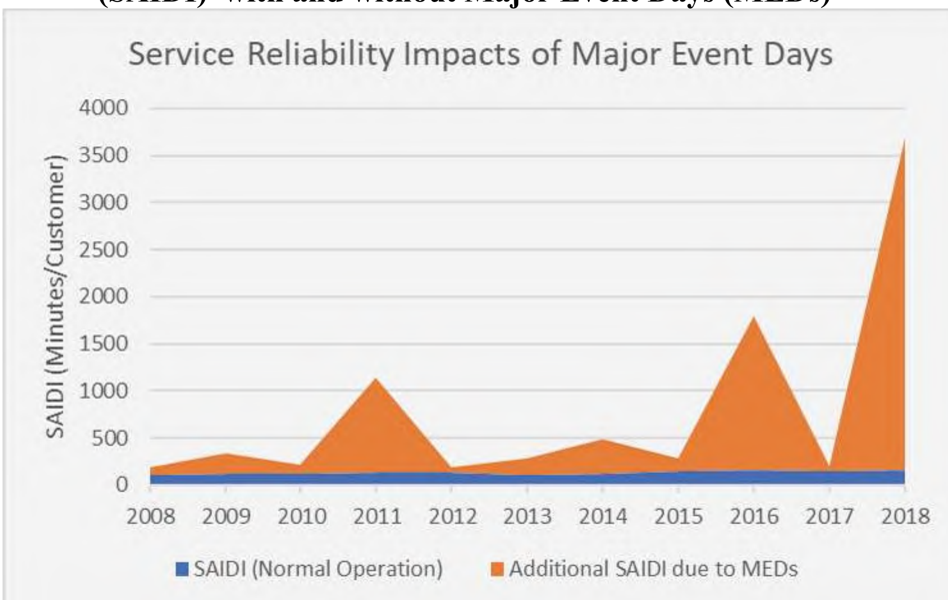
[98] North Carolina Institute for Climate Studies (2020, March). The North Carolina Science Report. Retrieved at: https://ncics.org/cics-news/the-north-carolina-climate-science-report/.
[99] S&P Global Ratings, (2019, May), Research Update: Duke Energy Corp. and Subs. Outlook Revised To Negative On Coal Ash Risks, Regulatory-Lag, And Project Delays. P. 4. Retrieved at Company Response to Public Staff Data Request 38-5.
[100] Company Response to Vote Solar Data Request 1-24.
[101] Morehouse, 2020.

interruption duration index ("SAIDI") in regular operation and during Major Event Days, which include but are not exclusively related to weather events.

Figure 2: Duke Energy Progress System Average Interruption Duration Index (SAIDI) with and without Major Event Days (MEDs)[102]



The Company's SAIDI trend over the last ten years shows a relatively flat SAIDI during normal operations, but increasing SAIDI impacts from major event days. While the major event days' occurrence is inherently stochastic, experts have found a statistically significant increase in major event days over time.[103] For context, the average customer was without power for 250 minutes in 2018,[104] and

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[102] Graph compiled using MED and non-MED SAIDI figures from Company Response to Vote Solar Data Request 1-25.

[103] Larsen, P., Sweeney, P., Hamachi-LaCommare, K., Eto, J., (2014, April). Exploring the Reliability of U.S Electric Utilities. Lawrence Berkeley National Laboratory, p. 29. Retrieved at http://www.usaee.org/usaee2014/submissions/OnlineProceedings/IAEE_ConferencePaper_01Apr2014.pdf.

[104] US Energy Information Administration ("EIA"), (2018, April), "Average frequency and duration of electric distribution outages vary by states." Retrieved at https://www.eia.gov/todayinenergy/detail.php?id=35652.

the cumulative improvement projected for phase one of the Grid Improvement Plan would reduce SAIDI by 49.23 minutes per customer.[105]

C. Financial Risks

Q. Please define climate-related financial risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related financial risks refer to impacts on the ability of a firm to access reliable and affordable financing due to climate change. Financial risks can be difficult to disaggregate from other risks because financial institutions' climate-related reasons for up- or down-grading a firm will often be linked to other climate-related impacts (e.g. downgrading a California utility due to exposure to wildfire risks). But the unique impacts of financial actions, and specific pathways by which these risks are expressed (e.g. downgrades, disinvestment, votes against board members, changes to stock price), merit treating financial risks as a separate category.

Investors are already paying special attention to electric utilities and their responses to climate-related risks. The Climate Action 100+, a global group of investors with over $35 trillion under management, identified 32 electric utilities as part of the hundred largest greenhouse gas emitters in the world.[106] Duke Energy Corporation is listed as one of the focus companies in the Climate Action 100+.

[105] Company response to Vote Solar Data Request 1-26.
[106] Climate Action 100+, (2019). *2019 Progress Report.* Retrieved at https://climateaction100.files.wordpress.com/2019/10/progressreport2019.pdf.

Credit rating agencies have already integrated a review of climate-risk, as a part of environmental, social, and governance ("ESG") review, into their credit ratings. S&P found in its lookback over ratings published 2015-2017 that environment and climate ("E&C") risks played an important role in over 700 cases, and over 100 listed E&C risks as a key factor. Of cases where E&C risks were a key factor, over 40 percent resulted in downgrades.[107] At the same time, S&P demonstrates that prudent management of energy & climate risk represents an opportunity for firms—20 upgrades listed E&C issues as a key factor.[108]

Investors like BlackRock and Morgan Stanley are also building analytical capacity to understand the distribution of climate-related risks. BlackRock and the Rhodium Group are using their plant-level climate risk findings to generate company-level climate-risk indices.[109] Using those indices, they find that climate-resilient utilities trade at a slight premium, while the most risk-exposed utilities trade at a discount.[110] An academic analysis of the relationship between climate risk, risk management, and financial health found similar results:

> "We document a positive correlation between cost of debt and carbon risk for firms [without awareness of climate risks]. Further, this association is economically meaningful, with a one standard deviation increase in carbon risk mapping into between a 38 and 62 basis point increase in the

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[107] Williams, J., & Wilkins, M., (2017, November), How Environmental And Climate Risks And Opportunities Factor Into Global Corporate Ratings – An Update. *S&P Global Ratings*. Retrieved at Company Response to Vote Solar Data Request 1-13, Docket No. E-7 Sub 1146.
[108] *Ibid.*
[109] Bertolotti et al.
[110] BlackRock, 2019.

> cost of debt. Equally, we find that the penalty is effectively negated for firms exhibiting carbon risk awareness."[111]

Q. How might climate-related financial risks affect the Company specifically?

A. Duke Energy Corporation's largest individual shareholders have taken strong positions on risks related to climate change and their likely response. Table 1 below demonstrates a selection of Duke Energy's creditors and their position on climate risks.

Table 1: Selection of Duke Energy Investors and Positions on Climate Risk

Shareholder	% Share of DUK	Climate-related Risk Position
Vanguard Group	8.19%*	"Many companies remain far beyond on their [climate-related risk] journey and have room to improve their disclosure and better educate their board on climate-related risks."[112]
Blackrock Fund Advisors	5.3%*	"In absence of robust disclosures, investors, including BlackRock, will increasingly conclude that companies are not adequately managing risk."[113]
State Street Advisors	5.15%*	"The vast majority of companies are taking a short-term, tactical approach to climate risk; they are failing to identify the long-term threats and opportunities created by a shift to a low-carbon economy and to incorporate this thinking into their boards' strategic planning."[114]

[111] Jung, J., Herbohn, K., Clarkson, P., (2018, July), "Carbon Risk, Carbon Risk Awareness, and the Cost of Debt Financing." *Journal of Business Ethics.*
[112] Vanguard (2019). Investment Stewardship 2019 Annual Report.
[113] Fink, 2020.
[114] State Street Global Advisors, (2019, June), Climate-Related Disclosures in Oil and Gas, Mining, and Utilities: The Current State and Opportunities for Improvement. Retrieved at

		Sent a letter to boards (January 2020) advising they would "take appropriate voting action" against board members of major US firms if they rated poorly on SSGA's ESG score and did not articulate how they would improve it.[115]
New York City Employees' Retirement System	**	Sent a letter to Duke Energy advocating for an ambitious climate goal. "This initiative makes clear that mobilizing for the planet goes hand-in-hand with protecting our pensions, and we need these commitments now."[116]

*: Top three individual investors
**: Investment share outside of top 10 are not published.

Credit rating agencies Moody's and S&P mention climate-related physical, regulatory, and economic risks in their updates on the Company and Duke Energy Corporation.[117] In and of themselves, the risks recorded in these updates may have negative impacts on the Company's business operations. But the financial community's awareness of these risks, and its potential reaction to those risks through stock price movement, shareholder action, and changes to credit ratings, present a unique challenge to the Company's business risks.

D. Economic Risks

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https://www.ssga.com/investment-topics/environmental-social-governance/2019/06/climate-disclosure-assesment.pdf.

[115] Wigglesworth, R., (2020, January), "State Street vows to turn up the heat on ESG standards." *Financial Times*. Retrieved at https://www.ft.com/content/cb1e2684-4152-11ea-a047-eae9bd51ceba.

[116] Kerber, R., (2019, February), "Big U.S. pension funds ask electric utilities for de-carbonization plans." *Reuters*. Retrieved at https://www.reuters.com/article/us-usa-utilities-investors/big-u-s-pension-funds-ask-electric-utilities-for-decarbonization-plans-idUSKCN1QH27D.

[117] Company Response to Vote Solar Data Request 1-24.

Q. Please define climate-related economic risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related economic risks are divided into technology risks and market risk. Technology risks refer to exposure of a firm's assets and operations from disruptive or innovative technologies that develop and mature through societal responses to climate change. In the electric utility sector, the principal technology risk is that of low- or no-carbon generation technologies like wind and solar displacing conventional generation and therefore "stranding" those assets' ability to recover their capital investment. As an example, NIPSCO and Tri-State recently recognized and corrected for climate-related technology risk by committing to shut down legacy coal assets in favor of a shift to renewables.[118] Analyses sponsored by both companies demonstrate the prudency of this decision: it will save money for these companies and ultimately for ratepayers.

Market risk refers generally to risks created by markets adapting to climate change. These risks are subtle and complex, especially in the energy sector, but one illustration might be customers opting out of typical utility service to pursue renewable options. Because of this complexity, this testimony will not analyze or evaluate market risks.

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[118] McMahon, J., (2019, July), "In Conservative Indiana, Utility Chooses Renewables Over Gas As It Retires Coal Early." *Forbes*. Retrieved at: https://www.forbes.com/sites/jeffmcmahon/2019/07/02/mike-pences-indiana-chooses-renewables-over-gas-as-it-retires-coal-early/#7cb3265243b4;
Best, A., (2020, January), "Tri-State CEO says wholesaler's clean energy transition will pay dividends." *Energy News Network.* Retrieved at: https://energynews.us/2020/01/21/west/tri-state-ceo-says-wholesalers-clean-energy-transition-will-pay-dividends/.

Analysts have focused particular attention on technology risks for utilities operating legacy coal assets. One analysis by Energy Innovation found that by 2025, new wind and solar would be less expensive than running 70percent of all coal assets in the United States.[119] Subsequent studies from Morgan Stanley and Moody's have corroborated those results.[120]

The same principle applies to gas generation. A study from the Rocky Mountain Institute found that a portfolio of clean energy technologies would deliver the same energy at a lower cost than 90 percent of gas-fired power plant capacity. The report ends with a recommendation to state utility regulators: "[a]ccount for the significant risk that uneconomic gas generation will increase customer rates."[121]

Q. How might climate-related economic risks affect the Company specifically?

A. The same national trends regarding coal and gas assets are also relevant in North Carolina. For coal assets, "[t]he trend is so strong that it is hard to imagine Southeastern utilities not relying heavily on solar and complementary load shifting resources to replace the coal and save customers money."[122]

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[119] Gimon, E., O'Boyle, M., Clack, Ct., McKee, S., (2019, March), The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. *Energy Innovation* and *Vibrant Clean Energy*. Retrieved at https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf.

[120] Smyth, J., (2019, December), "Financial analysts expect decarbonization will benefit utility ratepayers and shareholders." *Energy and Policy Institute.* Retrieved at: https://www.energyandpolicy.org/financial-analysts-expect-decarbonization-will-benefit-utility-ratepayers-and-shareholders/.

[121] Teplin, C., Dyson, M., Engel, A., Glazer, G., (2019), The Growing Market for Clean Energy Portfolios: Economic Opportunities for a Shift from New Gas-Fired Generation to Clean Energy Across the United States Electricity Industry. *Rocky Mountain Institute*, https://rmi.org/cep-reports.

[122] Gimon, et al.

In many cases, multiple climate-related trends can come together to cause an economic shift—a shift that the Duke Energy is already acknowledging. In describing the forces that led to the Company's decision to retire several coal plants, the Duke Energy Carolinas cites the following trends:

- On-going price declines and efficiency improvements of potential replacement including CTs, renewables and energy storage alternatives;
- Potential for increasing regulatory drivers including the release of the NC DEQ Climate Plan, NC Executive Order 80, and NCUC 2018 IRP Order requiring evaluation of accelerated coal plant retirements in future IRPs; and
- Potential for federal or state CO_2 legislation.[123]

Credit rating analysts are paying special attention to the Company's climate-related economic risks. Moody's 2019 credit rating for the Company found that "[DEC] has a moderate carbon transition risk within the regulated utility sector because, as an integrated utility, its generation ownership places it at a higher risk profile than transmission and distribution companies."[124]

Informally, Duke Energy Corporation officials have responded to the threat posed by renewables to gas generation and the inconsistency of gas generation with a carbon goal by proposing shorter depreciation periods for new gas generation—

[123] Duke Energy Carolinas Response to Tech Customers Data Request 3-26, Docket No. E-7, Sub 1214.
[124] Moody's Investor Service, (2019, March), "Duke Energy Progress, LLC." Retrieved at Company's Response to Vote Solar Data Request 1-24.

including periods as short as 15 years.[125] The necessary result of a shorter operating life, of course, is faster recovery of capital investment, driving higher annual costs and a higher average cost per kilowatt-hour. Duke Energy's potential decision to accelerate depreciation and increase ratepayer costs for these plants is, in and of itself, an example of climate-related risks increasing costs for ratepayers. These higher costs also increase the likelihood that renewables might be a more cost-effective option.

The risks of distributed generation referred to in Witness Hevert's testimony are examples of technology risk.[126] Hevert's testimony does not, however, acknowledge the benefits of customer-owned generation, which reduces the Company's exposure to climate-related risks as renewables come onto the grid. It is clear that distributed energy resources offer resilience benefits, and actors at the state and federal level are developing increasingly precise methods for valuing resiliency.[127]

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[125] Morehouse, C., (2019, October), Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon." *Utility Dive*. Retrieved at https://www.utilitydive.com/news/duke-vp-likens-gas-plant-buildout-strategy-to-15-year-home-mortgage-on-path/565328/.
[126] Direct Testimony of Robert B. Hevert ("Hevert Direct"), p. 48, l. 12-18.
[127] National Association of Regulatory Utility Commissioners, (2019, April). The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. Retrieved at: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

E. Regulatory Risks

Q. Please define climate-related regulatory risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related regulatory risks refer to negative impacts on a given firm due to policy changes that either seek to constrain actions that would exacerbate climate change, or incentivize actions that would ameliorate its impacts. Greenhouse gas emissions, for example, have until recently been an inextricable part of the electric utility industry, so a clear regulatory risk to electric utilities is constraints on these emissions or requirements to procure energy from renewable sources.

The United Nations Principles for Responsible Investment ("UNPRI") uses a framework called the Inevitable Policy Response ("IPR") to understand regulatory risk. This framework uses a more probabilistic model of climate policy: Instead of using a scenario-based "climate policy" and "no climate policy" approach, IPR asks when such a policy might be put in place. Using this framework, UNPRI found that a two-degree policy scenario (i.e., a scenario assuming an increase of two degrees Celsius in world temperatures) would on average lead to a 4 percent decrease in valuation for electric utilities. It also found electric utilities to have the widest variation in valuation adjustment by firm of any sector analyzed, with some firms decreasing in valuation by over 30 percent, and others increasing by the same margin.[128]

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[128] UN Principles for Responsible Investment (2019), Impacts of the Inevitable Policy Response on Equity Markets. Retrieved at https://www.unpri.org/download?ac=9857.

Financial observers are paying close attention to firms' policy, legal, and regulatory risks and their prudent management. S&P's lookback on the role of environment and climate factors in their credit ratings found that physical risks were the most cited type of risk, but policy risks were a close second—and the two of them were drivers of S&P rating decisions more than all other listed climate-related risks and opportunities combined.[129]

Q. How might climate-related regulatory risks affect the Company specifically?

A. Regulation of greenhouse gas emissions at the state or federal level would directly impact the Company's operations and planning. As the single largest owner of coal and gas generation capacity in 2018[130] and largest carbon emitter in the nation among electric power producers in 2019, [131] Duke Energy Corporation would likely face a substantial regulatory burden from passage of an emissions reduction scheme at any level. The share of generation capacity served by conventional generation (coal and gas) for the Company is approximately 50 percent, and according to its integrated resource plan ("IRP") that figure will in fact increase to 60 percent through 2034 (although the share of conventional generation will shift from coal to gas).[132]

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[129] Williams & Wilkins.
[130] Dholakia, G., (2019, December). Duke Energy tops operating US coal, gas capacity ownership. *S&P Global.* Retrieved at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/w4jueneo16bxoihgp-fhya2.
[131] Van Atten, C., Saha, A., Hellgren, L., Langlois, T, (2019, June), Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States. *MJ Bradley.* Retrieved at https://www.mjbradley.com/sites/default/files/Presentation_of_Results_2019.pdf.
[132] Duke Energy Progress (2019, September), Integrated Resource Plan: Update Report. pp. 9, Chart 2-A. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7f4b3176-95d8-425d-a36b-390e1e57a175.

Speculating on the likelihood of a federal climate policy is outside of the scope of this testimony, but recent developments at the state level, as discussed more in-depth in Section 4, suggest an increasing level of ambition by the states regarding greenhouse gas policy.

Preparation for uncertain outcomes is key to risk management and particularly apt for understanding regulatory risks. The Company, for example, already orients its planning around a tax on emissions beginning in 2025.[133] The level of tax used in the Company's planning starts at one-eighth the level of the tax proposed in September 2019 by the Climate Leadership Council, which counts Exelon, ExxonMobil, BP, Shell, and Vistra as members.[134]

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[133] Company Response to Vote Solar Data Request 1-27.
[134] Climate Leadership Council (2019, September). Our Plan. Retrieved at https://clcouncil.org/our-plan/.

F. Reputational Risks

Q. Please define climate-related reputational risks and summarize how they are expected to impact the electric utilities industry.

A. Climate-related reputational risks represent those tied to "changing customer or community perceptions of an organization's contribution to or detraction from the transition to a lower-carbon economy."[135] Electric utilities risk damage to their reputation if their response to climate change is out of line with stakeholders' expectations, from inadequate storm repair to continued investment in conventional electric generation technology without emissions controls.

Increasingly, electric utilities are managing their reputational risk by making commitments or announcements to decrease their greenhouse gas emissions. These announcements may increase goodwill, and potentially decrease the likelihood of new regulatory regimes that might mandate a decrease in emissions. At the same time, announcements in and of themselves may introduce reputational risks if firms do not appear to be honoring their public commitments.

Q. How might climate-related reputational risks affect the Company specifically?

A. A recent poll found North Carolina voters favor action to reduce carbon emissions,[136] and Duke Energy Corporation's recent shareholder resolutions show

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[135] TCFD Recommendations, p. 6.
[136] Global Strategy Group (2019, October). Regulating North Carolina's Carbon Pollution: Research Findings Prepared by Global Strategy Group for EDF Action. P. 6. Retrieved at https://www.edfaction.org/sites/edactionfund.org/files/u141/nc_carbon_limits_survey_analysis.pdf.

similar sentiment among the Company's shareholders.[137] As long as the Company's operations continue to emit carbon, the Company will likely be exposed to reputational risks. The Company also faces scrutiny due to ongoing coal ash remediation issues.[138]

Duke Energy Corporation announced its non-binding net-zero-by-2050 goal on September 17, 2019, establishing its presence in a growing cohort of large utility holding companies with ambitious carbon goals.[139] As discussed above, carbon announcements such as this one may mitigate some reputational risks but exacerbate others. Although the Corporation's goal is enterprise-wide, the Company would presumably need to follow a similar emissions path for the Corporation to meet its goals. However, the Company's projections in this case do not show that the Company will achieve them. Figure 3 shows the Company's projected carbon emissions as consistent with the higher carbon emissions contemplated in its IRP, in millions of tons of CO_2 emitted annually, compared to the emissions pathway needed to achieve the Corporation's goals for DEC.

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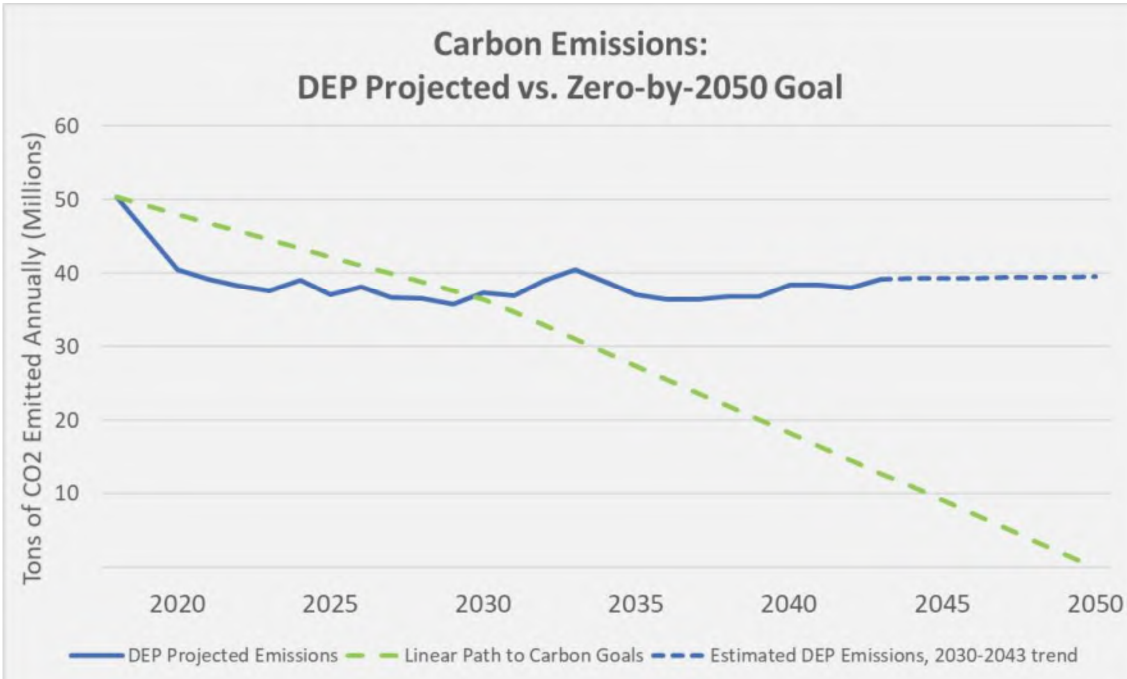
[137] Duke Energy (2019). Shareholder Proposals. Retrieved at: https://www.duke-energy.com/proxy/_/media/pdfs/our-company/investors/proxy/shareholder-proposal.pdf?la=en.
[138] Sorg, L. (2020, January). DEQ, Duke Energy, community groups strike deal on largest coal ash cleanup in US. *NC Policy Watch.* Retrieved at: http://www.ncpolicywatch.com/2020/01/02/deq-duke-energy-community-groups-strike-deal-on-largest-coal-ash-cleanup-in-us/.
[139] Gearino, D.

Figure 3: DEP Projected Emissions versus Pathway Consistent with Corporate Goals[140]



Thus, the emissions projected for purposes of this case do not comply with stated goals. Even worse, these projected carbon emissions are used to determine the value of carbon reductions created by the Grid Improvement Plan in the Company's cost-benefit analyses.[141] The result of these two decisions is that the Grid Improvement Plan's cost-benefit analysis is "taking credit" for carbon reduction that would not occur if the Company followed a path to achieving its carbon goal. The clear disconnect between the Corporation's public communications and the Company's statements in this proceeding represents a substantial reputational risk.

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[140] Graph compiled using projected annual CO2 emissions from Company response to Vote Solar Data Request 1-27 and Duke Energy Corporation's September 17, 2019 net-zero carbon emissions announcement.
[141] Oliver Direct, Ex. 7.

G. Commission Consideration of Climate Risk

Q. Based on your review of the literature and financial statements, are these risks material?

A. Yes. Based on a review of the available literature, the Company's filings, and the findings shown above, we assess climate-related risks are material to any electric utility's investments, costs, and operations, and they are specifically material to the Company in this proceeding.

Q. Does this testimony represent a comprehensive evaluation of the company's vulnerability to climate risks?

A. No. A comprehensive assessment of the Company's climate-related risks and the opportunities available in addressing those risks would require more operational data than is available to the public, consensus from a range of stakeholders, and a substantial analytical burden. As examples, the New York Storm Hardening & Resiliency Collaborative and Con Edison's Climate Change Vulnerability Study represent best practices in field of climate-related physical risks.

Q. How might the Commission view the TCFD climate-related risk framework?

A. As a regulator, the Commission has an important role to play in ensuring emergent risks are managed. (In fact, World Bank case studies on utility climate adaptation find that regulatory support is invaluable in incenting firms to act on long-term risks.)[142] At a minimum, the Commission may want to ensure that firms it regulates are aware of these risks and that its expectations of management are clear. The Commission could then support firms in meeting those expectations through information sharing and regulatory innovation. The Commission could use the TCFD framework as a tool-kit for categorizing risks and setting expectations for prudent management.

Q. Is the management of climate-related risks a critical component for keeping rates low for customers?

A. Yes. Managing climate-related risks is and will be integral to minimizing the costs imposed on customers associated with the impacts of climate change and ensuring the provision of safe and adequate utility service. Like any other business risk, the prudent management of climate risk will minimize those cost to the Company and, therefore, to customers.

Unlike other business risks, however, customers have their own direct exposure to climate-related risks. Proactive action is necessary to ensure that customers are best protected from climate-related risks and that they get reliable service when they need it most. Managing climate-related risks is in the interest of the Company and the public, a proposition that the Company seems to endorse based on its discovery responses.[143]

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[142] Audinet, P. (2014). Climate Risk Management Approaches in the Electricity Sector. *World Bank Group*. Retrieved at https://climate-adapt.eea.europa.eu/metadata/publications/climate-risk-management-approaches-in-the-electricity-sector-lessons-from-early-adapters.
[143] Company Response to Vote Solar Data Request 1-20.

Q. If the Commission or the Company adopted the climate-related risk framework, would the Company be expected to undertake major changes in its operations immediately?

A. No. Climate-related risks would represent an additional input to the Company's existing decision-making process. Decision-makers at the Company, and the associated oversight by regulators, would still weigh risks and opportunities across multiple dimensions when making business decisions.

Q. Do climate-related risks warrant considering an increase to the Company's allowed return on equity?

A. No. First, climate-related risks may be described as "asymmetrical" risks—that is, prudent management may avoid a decline in return on equity, but is less likely to result in a higher return on equity. Experts at the Brattle Group have noted that these risks are not suitable for addressing through a simple risk premium.[144] Second, exposure of the Company to these risks is at least partially dependent on the actions it takes in the operation and planning of its enterprise. Therefore, the risk for the Company is present only to the extent that it continues to pursue business decisions that ignore that risk. The same experts at the Brattle group note that "[i]t often may be easier to mitigate a risk directly rather than to measure its marginal effect on the cost of capital."[145] The California Public Utilities

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[144] Brattle Group, (2017), Compensating Risk in Evolving Utility Business Models. Pp. 14. Retrieved at https://brattlefiles.blob.core.windows.net/files/7264_compensating_risk_in_evolving_utility_business_models_august_2017.pdf.
[145] *Ibid.*, p. 16.

Commission addressed a similar issue with regard to wildfire risk and concluded: "The standard set in *Bluefield* and *Hope** is that investor-owned utilities should not be rewarded with an ROE that is inflated due to imprudent actions."[146]

H. Emerging Best Practices for Managing Climate-Related Risks

Q. Based on your review of the climate-related risk literature, have you identified best practices for managing climate-related risks?

A. Yes. The Task Force for Climate-Related Financial Disclosures recommends that firms exposed to climate-related risks and opportunities embed their climate strategy into the core of their business practices, then disclose to investors how they do so. TCFD recommends that accountability for climate strategy be embedded into the firm's board and management governance structure; that the firm's strategy at all levels be informed by climate risks and scenario-based planning around accelerated transitions; that risk management at all levels integrate climate-related risks; and that the firm's reported metrics and targets include exposure to climate risks and total carbon emissions.[147] As a non-financial sector with special exposure to physical and transition risks, TCFD recommends additional disclosures for

* *Bluefield* and *Hope* refers to *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia ("Bluefield")*, 262 U.S. 679 (1923) and *Federal Power Commission et al v. Hope Natural Gas Co. ("Hope")*, 320 U.S. 591, 603 (1944). These two cases set the precedent for a regulated utility's right to earn a reasonable rate of return on investments.

[146] California Public Utilities Commission, (2019, December). Decision on Test Year 2020 Cost of Capital for the Major Energy Companies. Application 19-04-014 et al. p. 36 (italics added). Retrieved at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M322/K633/322633896.PDF.

[147] Task Force on Climate-Related Financial Disclosures, (2017). Final Report: Recommendations of the Task Force on Climate-Related Financial Disclosures. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf.

electric utilities, including disclosure of internal carbon prices and capital expenditures on low-carbon generation assets.[148]

Q. Do climate-related risks apply only to the Company's generation assets?

A. No. In fact, climate-related risks span the whole of the Company's operations, from generation to consumer programs. Investments within the Grid Improvement Plan, for instance, are subject to climate-related physical risks (as we describe in Section 5). To the extent that the Grid Improvement Plan enables a transition to a de-carbonized and resilient grid, the investments also have implications for the Company's financial, economic, regulatory, and reputational risks.

Q. How have electric utilities responded to the onset of climate-related physical risks?

A. Even as early as 2014, electric utilities understood the need for guidance and recommendations on resilience to climate-related physical risks.[149] In 2015, the US Department of Energy convened the *Partnership for Energy Sector Climate Resilience*, a collaborative of 19 electric utilities supported by DOE in developing best practices for understanding climate-related vulnerabilities and establishing climate resilience.[150]

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[148] Task Force on Climate-Related Financial Disclosures, (2017). Implementing the Recommendations of the Task Force on Climate-Related Financial Disclosures. Retrieved at: https://www.fsb-tcfd.org/wp-content/uploads/2017/12/FINAL-TCFD-Annex-Amended-121517.pdf.

[149] Edison Electric Institute, (2014, March). *Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency.* Retrieved at https://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.

[150] US Department of Energy, (2016, September). *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning.* Retrieved at:

The partnership's *Guide for Climate Change Resilience Planning* describes a two-step process for resiliency. First, utilities should conduct a vulnerability assessment to understand their exposure and sensitivity to climate risks. Second, with the vulnerability assessment as an input, utilities can create a resilience plan that responds to those identified vulnerabilities, reviewing a wide range of resilience measures and using a systematic cost-benefit methodology that includes appropriate co-benefits.[151] This two-step process ensures that resiliency measures are designed with granular, up-to-date, high-quality information on vulnerabilities; use of a systematic cost-benefit analysis ensures that all resilience measures are fairly evaluated.

Q. Are there any examples or case studies of that would illustrate the implementation of best practices in climate-informed planning?

A. Yes. The work of the New York Storm Hardening & Resiliency Collaborative (consisting of Con Edison, Department of Public Service Staff, the City of New York, several environmental NGOs, and others) that emerged out of a settlement in Con Edison's 2013 rate case represents a good example of best practice in the industry. In its order approving Con Edison and public staff's settlement in the 2013 rate case, the New York Public Service Commission found that "[t]he Con Edison Resiliency Collaborative has provided a valuable focus for innovative approaches

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https://toolkit.climate.gov/sites/default/files/Climate%20Change%20and%20the%20Electricity%20Sector%20Guide%20for%20Climate%20Change%20Resilience%20Planning%20September%202016_0.pdf.

[151] *Ibid., p. 71.*

to the 21st century challenges to the utility system, and its work should continue, in public where appropriate."[152] The Collaborative reviewed Con Edison's proposed storm hardening investments, and also created a framework for climate vulnerability assessment, examined the applicability of non-wires resiliency strategies, and developed a robust cost-benefit analysis.[153]

Con Edison's complete climate risk vulnerability study was published in December 2019. The vulnerability study presents a comprehensive, forward-looking assessment of physical risks of climate change (including, for example, risks to workers due to higher frequency and intensity of heat waves) through an integrated framework of physical climate impacts, risks to assets and operations, and potential resilient solutions.[154] The study's use of the best available climate science—analyzed through a transparent, risk-based approach and considering a wide range of resilience solutions over the transmission and distribution system—represents a step forward for the industry.[155] The follow-up Climate Change Resilience Plan is due from Con Edison in December 2020.

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[152] Case 13-E-0030 *et al.;* Con Edison's Electric, Gas, and Stream Rates -- Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (2014, February). State of New York Public Service Commission. Retrieved at: https://climate.law.columbia.edu/sites/default/files/content/docs/Final-Order-2014-02-21%20(1).pdf.

[153] Case 13-E-0030 *et al,:* Consolidated Edison Company of New York, Storm Hardening and Resiliency Collaborative Phase Three Report. (2015, September).

[154] ConEdison, (2019, December). Climate Change Vulnerability Study. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.

[155] M.J. Bradley & Associates, (2019, December). Key Considerations for Electric Sector Climate Resilience Policy and Investments. Retrieved at https://www.mjbradley.com/sites/default/files/MJB%26A_KeyConsiderationsforClimateResiliencePolicyandInvestment.pdf.

Q. Based on the material you have reviewed, have you identified best practices for climate resilience?

A. Yes, with one caveat. First and foremost, climate-related risk management in electric utility distribution investments to date has focused exclusively on climate-related physical risks, without integrating financial, economic, regulatory, or reputational risks into risk assessment. Among the many co-benefits that enabling renewable distributed energy resources provides, for example, is that they provide a hedge to a given firm's regulatory and reputational risk.

Based on our review of emerging climate resilience plans, climate resilience plans proceed through two steps:

- **Forward-looking, high-quality vulnerability assessment.** The U.S. Department of Energy's North American Energy Resilience Model urges utilities to "transition from the current reactive state-of-practice to a new energy planning and operations paradigm in which we proactively anticipate [damage], predict associated outages, and recommend optimal mitigation strategies."[156] Utilities need to understand their exposure and vulnerability to climate-related risks before they can cost-effectively address them. Climate resilience plans undergo vulnerability studies that look at a wide variety of risks, integrate the most up-to-date scientific work on the matter, and project potential impacts of these risks

[156] Con Edison (2019, December). Climate Change Vulnerability Study. P. 63.

on specific assets in the future. High-quality vulnerability assessments both identify where the need for intervention is the greatest and provide a value "cost" input into the screen for solutions.

- **Informed, inclusive, and fair solution selection.** The process for identifying and selecting solutions should be robust, to ensure a true "no-regrets" approach. Solutions screens should be informed by the utility's vulnerability assessment, and they should include a stakeholder-informed wide range of traditional and non-traditional solutions. Finally, utilities and stakeholders should work together and agree on a cost-benefit methodology before considering any single intervention.

These steps are supported, in an optimal scenario, by collaboration with stakeholders throughout the process, including while setting a scope and goals for the climate resilience plan. Climate resilience plans are also iterative; as technology develops and vulnerabilities change, resilience plans must be updated.

4. DEVELOPMENTS IN NORTH CAROLINA'S BUSINESS AND POLICY ENVIRONMENT SINCE THE COMPANY'S MOST RECENT RATE CASE

Q. What policy developments, within North Carolina or with Duke Energy Corporation, have occurred since the Company filed its last rate case?

A. Three trends since 2017 are relevant to the Company's climate-related risks. First, state executive and regulatory agencies have announced or commenced new programs with implications for the state's electric utility industry. Second, Duke Energy Corporation made its non-binding carbon reduction goal announcement in September 2019. Third, ongoing, collaborative processes in North Carolina are creating state-of-the-art climate vulnerability data with implications for designing a more resilient electric grid for North Carolina.

Q. Please describe Executive Order 80 ("EO 80").

A. In order to "build resilient communities and develop strategies to mitigate and prepare for climate-related impacts in North Carolina," Governor Cooper's Executive Order 80 pledges the state to, among other things, reduce statewide emissions by 40 percent by 2025.[157] Importantly, the Executive Order directs several executive agencies to develop plans for reducing emissions from the energy and transportation sectors. An Interagency Council convened by the Executive Order may also recommend new and updated goals and actions to meaningfully address climate change. Executive Order 80 is provided as Exhibit JMV-TF-6.

[157] State of North Carolina Exec. Order No. 80, (2018, October).

Q. Please describe the Clean Energy Plan ("CEP").

A. The Clean Energy Plan is a collaborative, stakeholder-driven plan to "foster and encourage the utilization of clean energy resources," developed by the Department of Environmental Quality as directed by Executive Order 80.[158] After a year of conducting workshops and soliciting input from a diverse range of stakeholders, DEQ published its complete CEP in October 2019. The CEP sets ambitious goals for the energy sector, then presents several pathways to work toward those goals alongside short- and long-term actions over the next five years to move along those pathways. While the CEP itself is a complex document with six strategies and over 35 distinct recommendations, the key features of the Plan are summarized in Table 2.

[158] *Ibid.*

Table 2. Key Features of the Clean Energy Plan[159]

Goals	Key Recommendations	Relevant Stakeholders		
Reduce electric power sector emissions by 70% by 2030 and to net-zero by 2050;	Develop carbon reduction policy designs for retiring uneconomic coal; other market-based clean energy policy options	Legislature	NCUC	Governor's Office
Foster long-term energy affordability and price stability for residents and businesses;	Better align utility incentives with public interest, grid needs, and state policy.	State Agencies	Investor-Owned Utilities	Co-ops / Public Utilities
Accelerate clean energy innovation and deployment to create economic opportunities across the state	Modernize the grid to support clean energy resource adoption, resilience, other public interests.	Local Gvmnts	Academia	Business

Q. What are the implications of Executive Order 80 and the Clean Energy Plan on the Company's climate-related risk?

A. EO 80 and the CEP provide a meaningful signal for North Carolina regulatory agencies. They establish the procurement of clean energy and reduction of statewide emissions as a public policy objective and empower regulatory agencies to act in furtherance of that objective.

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[159] North Carolina Department of Environmental Quality, (2019, October), North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System. Retrieved at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

It is important to note that neither EO 80 nor the CEP has binding, legal enforceability for its goals. Nevertheless, the two actions may be seen as a directional signal for the future of climate policy in North Carolina.

The CEP also invites investor-owned utilities to act as partners in implementation. While it may be reasonable to see incipient carbon regulations as a regulatory risk, the Company's participation may represent a regulatory opportunity. Strategies B and C of the CEP seek to align interests between stakeholders on the 21st century utility business model and the future of utility system planning. By collaborating on innovative new regulatory mechanisms with public stakeholders, the Company could actually reduce regulatory lag and risks of other regulatory impacts to business operations.

DEQ's responsibility to develop a climate risk assessment and support communities in developing resilience also has implications to the Company. To the extent that electric system resiliency is a component of community resiliency, the Company will necessarily be a relevant party in communities' adaptation and resiliency plans.

Finally, EO 80 empowers the interagency council to recommend updated goals to meaningfully address climate change as appropriate. Therefore, while currently ongoing agency work in support of Executive Order 80 may already add climate-related regulatory risk and opportunities, there is potential for on-going long-term policy engagement between the Company and North Carolina executive agencies.

Q. Are there any public statements that the Company or its holding corporation has made that might impact the Commission's view of the Company's application?

A. Duke Energy Corporation published its non-binding net-zero carbon announcement on September 17, 2019.[160] In the announcement, the corporation projects it will decrease carbon emissions by 50 percent by 2030, with a goal of net-zero carbon emissions by 2050.

Q. What are the implications of Duke Energy Corporation's carbon announcement on the Company's climate-related risk?

A. While the Company is not explicitly required to meet Duke Energy Corporation's goals, the goal's ambitious timeline all but requires that the Company follow a similar emissions pathway if Duke Energy Corporation is to achieve its goals. As briefly discussed above, the carbon announcement has an impact on the Company's risk profile; while the urgency and regulatory burden of a regulatory or legislative mandate may be decreased by Duke Energy Corporation's commitment, Duke is also liable to sustain reputational damage and potential regulatory blowback if it is perceived to be missing its goals.

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[160] "Duke Energy aims to achieve net-zero carbon emissions by 2050." (2019, September), *Duke Energy News Center*. Retrieved at https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

Q. Are there ongoing processes to understand climate vulnerability and resiliency to infrastructure in North Carolina?

A. Yes. Work is currently underway within two projects related to both infrastructure and climate change in North Carolina, the results of which will be relevant for the Company's business operations. First, as directed by EO 80, the North Carolina Department of Environmental Quality is currently developing a North Carolina Risk Assessment and Resiliency Plan that will specifically address built infrastructure. As a part of the Risk Assessment and Resiliency Plan, the North Carolina Institute for Climate Research developed a high-quality climate science report that describes the physical impacts of climate change on North Carolina.[161]

Second, in part thanks to a grant from the U.S. Department of Energy, the North Carolina Clean Energy Technology Center, NC Department of Environmental Quality, and UNC Charlotte's Energy Production Infrastructure Center are participating in a two-year joint research project called "Planning an Affordable, Resilient, and Sustainable Grid in North Carolina."[162] Among other things, the project will take stakeholder input, assess new metrics for evaluating grid resiliency, and "enable a more decentralized, resilient grid." Both of these processes represent opportunities for the Company to meaningfully engage with

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[161] Kunkel, K., & Easterling, D.

[162] N.C. Clean Energy Technology Center (2020, January). Planning an Affordable, Resilient, and Sustainable Grid in North Carolina. Retrieved at: https://nccleantech.ncsu.edu/2020/01/29/planning-an-affordable-resilient-and-sustainable-grid-in-north-carolina-2/.

stakeholders who are generating meaningful, relevant information for a resilient, 21st century grid in North Carolina.

5. REVIEW OF THE GRID IMPROVEMENT PLAN IN LIGHT OF THESE RISKS

Q. What portions of the Company's application in this case are you addressing in your testimony?

A. As noted earlier, our review of the Company's application focuses on the Company's proposed Grid Improvement Plan ("GIP"). We review the Plan in light of grid modernization best practices, Vote Solar's participation in the stakeholder process, the emergence of climate-related risks, and recent policy development in North Carolina since the Company's last rate case.

Q. Does your testimony present a program-by-program review of the GIP?

A. No. We look to North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, North Carolina Sustainable Energy Association, and Southern Alliance for Clean Energy Witnesses Alvarez and Stephens for a granular review of the individual programs that form the GIP. The review in this testimony will focus more on the process by which the Company selected and scoped these programs and the broader implications for the development of the grid, rather than the technical details of each given program.

Q. What are the criteria that you would apply to a well-designed grid modernization plan in the context of this rate case?

A. While they represent an incomplete justification for any grid investment program, the "Megatrends" described in Witness Oliver's testimony succinctly describe the shifting dynamics of the electric grid. In our view, the Megatrends viewed together, however, do not provide justification for a slate of distribution projects; rather, they underscore the importance of the Company getting its investments in the grid right. The 21st century grid should be resilient to climate-related physical risks, but at the same time it must enable a more dynamic, communicative, and distributed energy system. And, being critical infrastructure for North Carolina, it must be reactive to ongoing physical, regulatory, and technical developments in the state. It's for this reason that the Department of Environmental Quality combines "grid modernization" and "grid resilience and flexibility" together in its Clean Energy Plan.[163]

The GIP, then, must play multiple roles for the North Carolina electric system. In the previous sections of this testimony, we have explored best practices for grid modernization and climate resilience. We re-produce those best practices, in no specific order, in Table 3 below:

Table 3: Best Practices for Climate Resilience and Grid Modernization

Climate Resilience	Grid Modernization
Forward-looking, high quality vulnerability assessment	Clear, Measurable Goals
	Integrated Distribution Planning
Informed, inclusive, and fair solutions selection	Stakeholder Engagement
	Cost/benefit analysis

[163] North Carolina Department of Environmental Quality (2019, October). North Carolina Clean Energy Plan. P. 82. Retrieved at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

A. Grid Modernization

Q. Please review the Grid Improvement Plan against grid modernization best practices.

A. Our review of the GIP against grid modernization best practices is summarized in Table 4, below:

Table 4. Grid Improvement Plan's performance versus Grid Modernization Best Practices

Best Practice	Grid Improvement Plan performance	Implications
Clear, measurable goals	Plan presents "Megatrends" but no measurable goals.	Unclear what 'success' looks like; no way to hold Company accountable; unclear benefits for ratepayers.
Integrated Distribution Planning	Plan will develop capability, but Phase I will not use it.	Plan does not adequately assess potential of NWAs; potential for sub-optimal investment.
Stakeholder Engagement	Company conducted several workshops; use of stakeholder input is not evident from application or stakeholder process.	Plan is less likely to incorporate a wide range of perspectives and value propositions
Cost-benefit analysis	Company does use cost-benefit analysis; no judgment of cost-benefit analysis in this testimony	No implications evaluated in this testimony

Q. Please explain the assessment of the GIP and its implications in Table 4.

A. **Clear, Measurable Goals:** As a $1.3 billion incremental investment in the grid with inevitable ratepayer cost implications, the GIP must demonstrate that the benefit provided to customers is worth the cost. The best way to do that is through clear, measurable goals and commitment to outcomes that benefit all stakeholders. These keep expectations for all parties aligned, and quantified goals allow stakeholders and regulators to track the Company's progress throughout the plan.

In lieu of stated goals, the Company offers its Megatrends[164] and Implications.[165] The Megatrends represent actual trends that are playing out on the grid, but we find their use alongside the Implications in this case to justify the Grid Improvement Plan to be inappropriate. The Company's analysis of the Megatrends provides no systematic, quantitative understanding of their impacts on the grid—thereby making effective "baselining" impossible. Notwithstanding the lack of an appropriate baseline, the Company does not set any goals for the Plan or metrics by which the Company, regulators, stakeholders, or ratepayers could assess the progress of the GIP or hold the Company accountable. The Company declines to demonstrate how any given project within the Plan relates to the Megatrends.[166] In light of the Plan's similarity to Power/Forward, it is difficult to ascertain how the development of the GIP was affected in any way by the Megatrends concept. In this way, the Megatrends may be characterized as *post hoc* justification for Power/Forward projects, rather than a representation of discrete problems that must be addressed with targeted solutions.

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[164] Oliver, Ex. 2.
[165] Oliver, Ex. 3.
[166] Company Response to Vote Solar Data Request 1-21.

Integrated Distribution Planning ("IDP"): Simply put, integrated distribution planning is the element that enables utilities to "modernize" their grid. The analytical capability that is a hallmark of IDP processes allows electric utilities to understand grid operations at a more granular level, work with the distribution gird as an integrated system, and as a result precisely take advantage of distributed resources and place grid modernization solutions. The Company has proposed IDP components as a part of the GIP, but these components will be pursued alongside, rather than in advance of, massive capital investment in the grid. Pursuing $1.3 billion in distribution-level investments[167] (just before these IDP capabilities are online) risks premature deployment of these assets and therefore a sub-optimal cost-benefit for all stakeholders, including the Company.

Stakeholder engagement: Stakeholder engagement for the GIP has been reviewed above. The process executed by the Company did not adhere to best practices for an effective process and appears to have minimally incorporated stakeholder input.

Cost-benefit analysis: This review will not cover cost-benefit analysis in depth. Similarly, cost-benefit analysis has not been the focus of this testimony and will not be reviewed.

[167] Oliver Direct, Ex. 10, p. 3.

Q. The Company claims that the projects included as part of the GIP are "no-regrets," "foundational" projects. Do you agree with that characterization?

A. No. First, the "modernize" projects that Witness Oliver describes as "foundational"[168] represent just over a quarter of the total budget of the Plan.[169] Even describing the Plan in the Company's terms, it would be inappropriate to describe the entire plan as "foundational."

Second, many of the projects proposed under the GIP fall into what GridLab calls "geographical" projects—physical infrastructure installed in specific geographical areas to extend some grid capability.[170] GridLab's report points out that the "need" to extend new capabilities to these areas should emerge from a high-quality, risk-based assessment of vulnerability of current operations. "Foundational" investments are those that make such a need assessment possible, or enable the 'capability' that is being extended through geographical investment. ISOP is the paramount example of a "foundational" investment. The Company's proposed Self-Optimizing Grid, for example, would not qualify as "foundational." Some of the projects categorized as "modernize" by the Company, such as distribution system and transmission system automation, would also fall into the "geographical" category.

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[168] Oliver Direct, p. 30, l. 7.
[169] Oliver Direct Ex. 12, p. 97.
[170] Alvarez, P., & Stephens, D., p. 16.

Q. Does the Company acknowledge that making investments without all necessary information could lead to sub-optimal or imprudent investment?

A. Yes. In a response to a stakeholder question, the Company responded that it was confident "with 85% certainty" that ISOP would not render GIP investments obsolete.[171] This figure was clearly not intended as a precise estimate, but it provides a helpful estimate for understanding potential losses. To put this number into context, if 15 percent of GIP investment were rendered obsolete by ISOP capabilities, the Grid Improvement Plan as proposed would immediately result in stranded distribution assets worth just under $200 million.[172] The Company must take this risk seriously, and its failure to do so in this proposal represents a major oversight.

Q. Does the GIP's use of Megatrends and implications represent a prudent management of climate-related risks?

A. In short, no. The Company has failed to demonstrate how any specific projects addresses climate-related impacts,[173] and its approach does not acknowledge the interconnectedness of climate-related risks across generation, transmission, and distribution functions. Making new investments in distribution infrastructure without a systematic assessment or climate-specific data gathering is an insufficient response to climate-related risks. The Company's current approach of willful

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[171] Oliver Direct Ex. 13, p. 43.
[172] Oliver Direct, Ex. 10, p. 3.
[173] Company Response to Vote Solar DR 1-7 and 1-8.

avoidance of climate analysis is inadequate, if not imprudent, and exposes the currently proposed grid investments to unnecessary and manageable risks.

B. Climate Resilience

Q. Please review the GIP against grid modernization best practices.

A. Our review of the GIP against climate resilience plan best practices is summarized in Table 5, below.

Table 5. Grid Improvement Plan's performance versus Climate Resilience Best Practices

Best Practice	Grid Improvement Plan performance	Implications
Forward-looking, high-quality vulnerability assessment	Plan did not utilize any meaningful climate risk assessment.	Ongoing physical risks to grid assets and reliability; less cost-effective projects.
Informed, Inclusive, and Fair Solutions Selection	Plan uses a solutions-first approach and cost-benefit analysis developed after the fact.	Non-'traditional' alternatives likely excluded from Plan; missing potential co-benefits.

Q. Does the Company explicitly acknowledge the presence of climate-related risks or make any attempt to systematically manage them in its application or in discovery?

A. No. As noted above, the Company has represented that it has incorporated climate-related risk only to the extent that it is included as part of the "Megatrends" identified by the Company,[174] although it also stated that it is "without knowledge" as to the role of climate change in weather events.[175]

Q. Please explain your assessment of the GIP and the implications of the Plan in Table 5.

A. **High-quality Risk Assessment:** We conducted an in-depth comparison of risk assessment and solution selection between the GIP and Con Edison's Climate Change Vulnerability Study. The results of that comparison are presented in Exhibit JMV-TF-7. Con Edison's climate vulnerability study estimated that climate risks would cost the utility between $1.3 and $4.6 billion by 2050,[176] while the Company, for its part, has presented no quantitative risks of climate-related risks. As an example of a potential risk identified by Con Edison but ignored by the Company, Con Edison estimates that flood risks may exceed design specifications by as early as 2030.[177]

The comparison shows that, compared to the industry standard and even a reasonable understanding of climate-related risks, the Company did not complete any systematic climate risk assessment of its assets or operations. There may be individual examinations of factors that may be impacted by climate change, such as flood risk, but those analyses are backward-looking and do not incorporate likely

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[174] Company Response to Vote Solar Data Request 1-3.
[175] Company Response to Vote Solar Data Request 1-6.
[176] Consolidated Edison Company of New York Inc. ("ConEd"), (2019, December). Climate Change Vulnerability Study ("ConEd Climate Study"). P. 4. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[177] ConEd Climate Study, p.5.

future climate impacts.[178] The Company's risk assessment is mostly represented by the "Implications" of its Megatrends, which are simply too high-level and qualitative to precisely design a programmatic intervention. In comparison, the Con Edison Vulnerability Study pursued an asset-level risk screen, mirroring the granularity of studies conducted by financial institutions and discussed earlier in this testimony.[179]

Like any other business risk, when climate-related risks are not managed, the Company (and therefore its customers) are more exposed to negative outcomes. And, as we have discussed above, physical risks may spill over into insurance, financial, reputational, or regulatory risks.

Informed, Inclusive, and Fair Solutions Selection: Witness Oliver summarizes the process by which the GIP was developed in his testimony.[180] The process was not conducted in collaboration with stakeholders; beyond identifying the existence of the Megatrends, there are no stated goals; solutions are not informed by high quality vulnerability assessment; selection criteria are not defined, beyond vague programmatic terminology;[181] there is no indication for how the geography or scale of any given intervention was decided; "tools" are a narrow range of traditional solutions; and cost-benefit was performed after the fact, rather

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[178] Company Response to Vote Solar Data Request 1-12.
[179] Bertolotti et al.
[180] Oliver Direct, p. 29, l.18 – p. 30, l. 18.
[181] Oliver Direct, Ex. 5.

than designed in advance of the consideration of any particular project and used as a screening tool.

This approach constrains what is possible under the GIP. It leaves very little room for assessment of co-benefits, pre-determines a narrow set of potential solutions, and ignores non-wires or non-standard alternatives.

C. North Carolina Context

Q. Does this process acknowledge the other, ongoing processes to quantify grid vulnerability, modernize the electric system, or increase resilience in North Carolina?

A. No. Witness Oliver's testimony does not mention "Clean Energy Plan" or "Executive Order 80," nor does it refer to either ongoing research project we discuss above.[182] Although one of the identified Megatrends is "Environmental Trends" or "Environmental Commitments," its description of these environmental commitments is exclusively backward-looking.[183] Discussion of environmental commitments in Oliver Exhibit 4 do not mention the Clean Energy Plan or Executive Order 80.

Q. What are the implications of this omission?

A. It's an unfortunate disconnect between a potentially large investment of assets on the grid through the GIP, unfolding at the same time as many simultaneous conversations are developing in the North Carolina policy community. For the

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[182] Oliver Direct.
[183] Oliver Direct, Exhibit 4.

Company, not engaging with these processes misses an opportunity to gain working knowledge that could inform the details of the Plan, and increases the potential for obsolescence, stranded assets, or increased costs because of an operations and communication disconnect between Company practice and regulatory policy.

D. Review Overall

Q. Do you see an opportunity for an effective grid modernization and climate resiliency proposal at this time in North Carolina?

A. Yes. We agree that recent trends are changing the way customers use the grid and, as we demonstrate above, climate-related risks and opportunities will shape the electric utility business moving into the future. At the same time, a natural synergy exists between the Company's engagement in integrated planning and circuit-level analysis through ISOP and Advanced Distribution Planning and the vibrant policy conversation in North Carolina discussing the very nature of the grid in the 21st century. And, as we document in Section 2, best practices from other states and proceedings are emerging to light the way toward a clear grid modernization and climate resiliency plan that has benefits for all stakeholders. A truly collaborative grid modernization process that creates goals and accountability in partnership with stakeholders, gathers all of critical information (including climate-risk-related and distribution operations information) needed for grid planning first, then selects projects through an open and transparent process, could deliver substantial, lasting benefits for all stakeholders.

Q. Does the GIP deliver on the potential for a well-designed grid modernization or climate resilience plan?

A. No. As we discussed above, the Company does not have the input from stakeholders (including state executive agencies), climate-related factors, or distribution-level analysis it needs to design a true no-regrets Plan. Partly as a result, the Plan does not contain overall goals or tracking metrics that would allow stakeholders and regulators to maintain reliability. Finally, instead of engaging in an open, transparent assessment of solutions and investments (including non-wires alternatives and distributed energy resources), the majority of the Plan consists of solutions that were proposed under Power/Forward.[184]

As a result, there is a massive potential opportunity cost for proceeding with this plan. At a time when best practices are emerging from a changing national landscape, the Company's own sophisticated distribution planning capabilities are coming online, and stakeholders are proactively pursuing deep, informed engagement, the Company's proposal does not take advantage of those developments. According to the Company's informal assessment, the opportunity costs from declining to inform its Plan with advanced distribution planning could be around $200 million, as described above.[185] Because the Company has not undertaken an assessment of its climate risks, that opportunity cost remains unquantified.

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[184] Company Response to Vote Solar Data Request 1-2.
[185] Oliver Direct, Ex. 13, p. 43.

Q. Do you believe that a positive benefit-cost ratio is sufficient justification for moving forward with any given project?

A. No. Cost-benefit analyses answer the question, "How does this investment compare to business-as-usual, or no intervention at all?" As stakeholders in the modernization of the grid, the answer we should be more concerned with is "how does this investment compare to a well-executed grid modernization and climate resilience plan in the public interest?" Against this counterfactual, a project with a positive benefit-to-cost ratio might still represent a missed opportunity. Because the Company did not effectively pursue a climate vulnerability study, stakeholder input, or integrated distribution planning, it lacks the information needed to conduct such a comparison.

Q. What role could distributed energy resources (DERs) play in grid modernization and climate resilience?

A. DERs bring unique benefits to both grid modernization and climate resilience program goals. A comprehensive grid modernization or climate resilience plan should ensure that DERs are fully valued versus traditional solutions.

In a climate resiliency context, DERs provide the critical service of generating energy close to load. When distribution or transmission systems are not working at full capacity, such as during extreme weather events, "islandable" DERs can continue to provide power to ratepayers.[186]

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[186] ConEd Climate Study, p. 49.

In a grid modernization context, DERs may be able to fulfill distribution system operational needs more cost effectively than traditional investments, or defer the need for incremental investments in distribution assets. In this context, DERs are often referred to as non-wires alternatives ("NWAs") or non-traditional solutions ("NTS"). A recent Duke Energy webinar demonstrating the anticipated functionality of ISOP explained that ISOP analytical capability would be able to weigh benefits of DERs versus traditional solutions and identify where NWAs might be more cost-effective.[187] A typical deferred investment by NWAs is increased line capacity, which is a major component of the Self-Optimizing Grid GIP project.[188]

Q. Do you believe the Grid Improvement Plan appropriately considered DERs and NWAs in the development of potential solutions?

A. No. DERs and NWAs are disruptive solutions, and they require proactive analysis and planning to be fully valued in utility planning. First, the utility needs the data to understand DER benefits. That includes both climate vulnerability, ascertained through a vulnerability study as demonstrated above, and detailed distribution operations data created through an integrated distribution planning process. Then, the utility should use a systematic solutions selection process that incorporates

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[187] Duke Energy (2020, January). ISOP Stakeholder Webinar. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/200062/isop-webinar-1-presentation.pdf?la=en.
[188] Oliver, Ex. 10.

climate and distribution data, puts a value on co-benefits, and fairly values DERs against traditional solutions.

The Company did not pursue these steps before developing the GIP. By pursuing its grid modernization planning in this manner, the Company constrained the role of DERs in its Plan and likely lost potential cost-effectiveness benefits for both the Company and its customers.

Q. Are there any programs proposed in the GIP that you approve?

A. Yes. The Integrated Systems & Operations Planning program is a truly innovative program that could enable a more dynamic grid, and its Advanced Distribution Planning and Morecast components both represent major steps forward in analytical capacities for distribution planning. We support this program.

Similarly, IVVC is a program with a high benefit-to-cost ratio and many clear benefits. We support the Company's investment in this program.

6. DISCUSSION OF THE COMPANY'S GRID IMPROVEMENT PLAN AND THE BURDEN OF PROOF

A. Deferral Accounting Request

Q. Describe the Company's request for approval of deferral accounting.

A. The Company is requesting to defer costs related to the Grid Improvement Plan into a regulatory asset for recovery in future rate cases.[189] More specifically, the Company is requesting deferral of the North Carolina retail share of the following types of costs for its GIP: depreciation of capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, O&M expense related to the installation of equipment, property tax related to the capital investments, and a return of the balance of costs deferred at the Company's weighted average cost of capital.[190]

Q. Is use of deferral accounting for the types of investments in the GIP in years 2020 through 2022 typical in the utility industry?

A. No. Deferred accounting by its very nature is an extraordinary ratemaking tool, and it would be a departure from customary ratemaking practices to use deferred accounting in these particular circumstances.

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[189] Direct Testimony of Company Witness Kim H. Smith ("Smith Direct"), p. 37-38.
[190] Smith Direct, p. 38, l. 1-5.

Q. Why is deferral accounting considered extraordinary relief in regulatory practice?

A. The strong presumption is that general rate proceedings are the primary forum for evaluating the prudence of utility investments, updating the utility rate base to reflect the addition of such investments, and capturing in rates the impact on operating expenses, deprecation and return associated with such investments. In the case of large capital investments, the use of an allowance for funds used during construction ("AFUDC") typically provides adequate compensation for a utility's undertaking of significant multi-year investments. Through AFUDC, the utility is allowed to capitalize the financing costs of such investments prior to their completion and inclusion in rate base, with such capitalized costs being added to the original investment upon which the utility is allowed to earn a return and which is amortized over time through depreciation. This is the ordinary and routine ratemaking process for large capital investments.

Q. Why is the Company seeking extraordinary treatment for the GIP investments made in years 2020 through 2022 in this case?

A. The Company contends that costs related to the GIP are "major, non-routine investments, that produce substantial customer benefit," and that this description "meets the Commission's traditional test for deferral." Company Witness Smith also claims that absent deferral the Company will "experience a significant adverse earnings impact."[191] According to the Company's testimony, in the absence of the requested deferred accounting treatment, the "earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the plan."[192]

Q. Is the relief sought in this case similar to the relief sought in the last case with the Power/Forward grid investment and modernization initiative?

A. No. Although Power/Forward was mentioned in the previous rate case, no extraordinary regulatory treatment was sought.[193] However, relief sought in this case is similar to the relief sought by Duke Energy Carolinas in its most recent rate case. As discussed above, in its previous rate case, DEC sought permission to recover Power/Forward costs through either a bill rider or deferral into a regulatory asset for similar cited reasons.[194]

Q. Why did the Commission deny extraordinary treatment of expenses incurred outside of the test year in the previous rate case?

A. As cited above, the Commission found that "the reasons DEC says underlie the need to Power Forward are not unique or extraordinary… [they] are all issues the Company [has] to confront in the normal course of providing electric service… A

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[191] Smith Direct, p. 39, ll. 2-9.
[192] Smith Direct, p. 39, ll. 3-5.
[193] Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, Docket No. E-2, Sub 1142. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d2b2a1a0-dae1-45de-af9c-c987d4aeddc8.
[194] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 et al. p. 142-145. Retrieved at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

number of the Power Forward programs …are the kinds of activities in which the Company engages or should engage on a routine and continuous basis."[195]

[195] *Ibid,.* p. 146.

Q. Are you aware of Senate Bill 559, which was passed by the North Carolina General Assembly in 2019?

A. Yes. My understanding of Senate Bill 559 is that a major feature eliminated from the bill before it passed would have authorized utilities to request, and the Commission to grant, multi-year rate plans.

Q. Would a multi-year rate plan provide a means for addressing situation for which the Company is seeking extraordinary relief for these GIP expenses incurred outside of the test year?

A. Yes. While the elements of a multi-year rate plan would typically be established through the ratemaking process, a likely element would be the periodic updating of the utility's rate base to reflect anticipated major capital investments, such as the GIP. Allowing the utility to update its rate base to include such investments (and the associated expenses) would go a long way towards eliminating the impact of regulatory lag, which seems to be the primary motivation in the Company's request for deferred accounting in this case. According to the Company, in the absence of deferred accounting, its earned return on equity would erode by 100 basis points by the end of the third year of the GIP. (Of course, that assumes the Company would not file more frequent rate cases as a means of updating its rate base, which is another tool available to a utility to minimize the impact of regulatory lag.)

Q. Based on your knowledge of other states, do multi-year rate plans provide a more appropriate basis for regulatory consideration of forward year investments, such as those sought here?

A. Multi-year rate plans are certainly one means of addressing the issue, assuming there is the statutory authority for entering into such plans. (Even in the absence of express statutory authority, it is sometimes possible for multi-year rate plans to be implemented through agreement by all parties in a proceeding, as is commonly done through settlements in rate cases involving the New York electric utilities.) As part of a multi-year rate plan, I would expect to see a mechanism established that would provide the same level of scrutiny for evaluating the prudence of forward year investments. In other words, the traditional general rate case process provides a good forum for closely scrutinizing the reasonableness of the expenditures and whether the utility has borne its burden of proof in showing that it is undertaking such investments in a manner that minimizes the long-term costs for its customers. Any multi-year rate plan would need to include a process that includes these essential protections for customers. We discuss this in the following section.

Q. Why would a major, comprehensive grid investment scheme like GIP not fit within a utility's ordinary course of seeking cost recovery through rate cases?

A. It typically would, for the reasons stated above, and the Company has the burden to show why the extraordinary remedy of deferred accounting is necessary. As noted above, the Company's position is that the GIP comprises "major, non-routine investments, that produce substantial customer benefit," and that its request "meets the Commission's traditional test for deferral." Whether or not the Company's proposal is acceptable to the Commission, of course, is entirely up to the Commission; as discussed below, the Commission has substantial discretion in deciding whether or not to allow deferred accounting, and to define the terms under which deferred accounting will be allowed.

Q. When generation and transmission projects are proposed, which are often multiple-year construction projects with long lead times, does the Commission have a process for determining whether the project is necessary?

A. Yes. It is fairly common for utilities to be required to secure a Certificate of Public Convenience and Necessity ("CPCN"), which requires the utility to demonstrate that the generating or transmission project is necessary and that the costs are reasonable. North Carolina has a similar requirement in the case of generating plants (NC GS 110.1) and transmission lines (NC GS 62-105a).

Q. Do major, comprehensive grid investment schemes like the GIP fall within a regulatory gap?

A. I think the Company has made a decent case that the current ratemaking mechanisms available to it do not fit well with the type of projects comprising the GIP. As described in the Company's testimony, most of the projects included within the GIP do not, because of their magnitude and duration, qualify for the AFUDC treatment that was mentioned earlier. There will be some earnings erosion associated with implementing the GIP in the absence of deferred accounting or a multi-year rate plan that includes periodic updating of the Company's rate base. In addition to the earnings impacts, there is probably a strong basis for providing a regulatory forum for evaluating and approving a comprehensive multi-year program that does not fit neatly within the standard general rate case.

Q. Are major, comprehensive grid investment schemes like the GIP more prevalent around the country in the last decade?

A. Yes, there are several states that are moving towards a more comprehensive grid planning process, given the fundamental changes that are underway in the electric utility industry. For the most part, this process is necessary to accommodate the expanded use of DERs given the failure of traditional planning processes to integrate DERs into long-term planning (which historically was based on one-way power flows from the utility's large, centralized generating stations to end use customers). Both California and New York are well down the path of requiring utilities to engage with stakeholders in distribution system planning which, among other things, identifies the opportunities for strategic deployment of DERs by third parties that can result in lower costs to ratepayers over time. Another driver for comprehensive grid planning is addressing the impacts of climate change, which similarly requires a departure from the traditional planning model that was based largely on historical trends in customer and load growth rather than considering the impact of rising temperatures and sea level, and the increasing frequency of extreme weather events.

Q. Does a deferral accounting request, such as the Company has proposed here for the GIP expenses incurred in the years 2020 through 2022, provide the

Commission the same opportunity to evaluate the reasonableness of the proposed investments before they are built as a CPCN process?

A. No. Deferred accounting, almost by its very nature, does not produce the same level of regulatory scrutiny as is afforded by the traditional ratemaking processes of general rate cases and the CPCN process.

Q. Does the practice of using the extraordinary relief of deferral accounting for the GIP shift risks to ratepayers?

A. Yes. In general, ratepayers' interests are well-served by the reliance on traditional general rate cases for setting rates, and the associated regulatory lag that produces a strong incentive for a utility to manage its costs. Streamlining that process through the use of deferred accounting reduces the regulatory oversight that results from the general rate case process, and largely eliminates the economic incentive from regulatory lag to manage costs.

Q. Going forward, do you have any recommendations for addressing this current regulatory gap to provide better oversight of forward year investment schemes for the Commission and steady revenue recovery for the Company?

A. Yes. As discussed in the next section, we recommend a regulatory scheme that involves (1) a rigorous planning process that, among other things, properly integrates the impacts of climate change, and (2) addresses the Company's legitimate concerns about rate recovery while providing strong incentives for the Company to engage in a planning process that is geared toward minimizing the costs borne by its customers over time (which necessarily requires the integration of climate change impacts).

B. Need for an Integrated System Planning Process

Q. Please describe the integrated system planning that you are recommending.

A. Future investments in the Company's grid must be subject to a process that thoroughly considers the impacts of such investments in addressing, and minimizing, climate change-related impacts. Given what we know about the impact of past extreme weather events on the Company's system, it is imperative that any future grid investment be evaluated in light of the Company's vulnerability to climate-driven risks, and how such investments address those risks. Such an analysis is essential if the Commission is to fulfill its obligation to minimize the long-term rate impacts to the Company's customers, and to maximize the reliability (at reasonable costs) of the electric service provided to the Company's customers.

Q. Is there any precedent of a utility commission initiating such a process as an outcome of a general rate case proceeding?

A. Yes. The process with which we are most familiar is the Con Edison rate proceeding initiated in New York in early 2013, following the impact of Superstorm Sandy.

Q. How is the Con Edison rate case example similar to the current case?

A. Following Superstorm Sandy in October 2012, Con Edison in January 2013 filed a massive general rate request proposing to "harden the utility's system" in response to Con Edison's experience in coping with Superstorm Sandy. Among other things, Con Edison promised to spend $1 billion over the next four years to harden its system in response to what it learned during Superstorm Sandy. In response, several environmental organizations filed testimony as the "Clean Energy Parties" to propose a different strategy, based on lessons learned in terms of "where the lights stayed on" during Superstorm Sandy (i.e., areas served by microgrids and DERs). Among other things, the Clean Energy Parties proposed that Con Edison's proposed grid expenditures be subjected to a rigorous examination of their resilience benefits, by subjecting the expenditures to examination by a Storm Hardening and Resiliency Collaborative. In other words, rather than following a "business as usual" approach of spending money to harden the system in light of the most recent extreme weather event, the utility was expected to evaluate its T&D expenditures in a manner that would improve its grid resilience in light of climate change and the increasing frequency of extreme weather events. That process ultimately led to the development of the Climate Change Vulnerability Study, which was released by Con Edison in December 2019 and is attached as Exhibit JMV-TF-4.

Q. In what ways does the climate resilience grid investment strategy outlined in the Con Edison Climate Change Vulnerability Study similar to the GIP?

A. There is very little similarity to the rigorous process followed by Con Edison in its Climate Change Vulnerability Study to the process followed by the Company in developing its GIP. In contrast to the Company's failure to consider the impact of likely trends with respect to temperature, sea level rise or the frequency of extreme weather events, the Climate Change Vulnerability Study performed by Con Edison considered the range of scenarios involving, among other things, anticipated temperature, humidity and sea level increases, as well as the frequency of extreme weather events, and evaluated the value of its grid investments according to the resilience benefits that such investments would provide to the grid.

Q. Compared to the recommended grid investment strategy outlined in the Con Edison report, does the GIP present a comprehensive strategy to approach resiliency on a system-wide basis?

A. No, the Company's Grid Improvement Plan is woefully deficient with respect to the integration of climate change impacts in its long-term planning, for the reasons discussed in the preceding section.

Q. Based on your experience, what process provides the best means to match the state policy goals with the Company's stated investment strategy and objectives?

A. As described in the preceding sections of this testimony, North Carolina has recognized the imminent threat associated with climate change, and has articulated broad policy objectives that are consistent with minimizing that threat—through mitigation measures such as reduction in GHG emissions—as well as the measures necessary to address adaptation to the "new normal" going forward. The Company's GIP neither addresses the mitigation possibilities nor the adaptation measures that are necessary to cope with climate change-related risks through achieving increased resilience in the Company's network.

C. Prudency and Burden of Proof in Light of Climate-Related Risks

Q. What is the utility's obligation to address the risks associated with climate change in its rate filings?

A. Nothing is different about the utility's obligation to demonstrate that its actions—as incorporated in its rate proposals—reflect the investments and expenditures that result in the lowest costs to customers over time. In order to recover their proposed expenditures in rates, utilities generally must demonstrate that they are prudently managing their expenses, and proceeding down a path of making investments and incurring expenditures that result in reasonable rates to customers over time. The risks associated with climate change now need to be part of that ratemaking equation. If utilities fail to take climate change risks into account, and continue to make investments in T&D infrastructure or incur other expenditures that fail to improve the resilience of the utility grid in the face of climate change, they run the risk of having those investments disallowed as imprudent. As a matter of prudent utility practice, utilities have the obligation to demonstrate that they have integrated the risks associated with climate change into their long-term planning for T&D investments, and the associated expenditures.

Q. How does the threat of climate change affect the utility's burden of proof in rate proceedings?

A. If a utility fails to demonstrate that it is proceeding down a path that takes climate change-related risks into account and minimizes the costs to customers after taking those associated climate change-related risks into account, their T&D investments (and associated expenditures) are subject to disallowance. It is the "new normal" with respect to prudent utility practice. It is no longer acceptable to expect to recover in rates the investments that are made, if such investments are not mindful of the impacts of climate change and are not designed to improve grid resilience in light of such climate change.

Q. How would you define adequate consideration of climate vulnerabilities?

A. The Con Edison Climate Change Vulnerability Study probably represents the current state of the art in demonstrating how an electric utility should integrate the likely impacts of climate change in its long-term planning process. The extent to which utilities should be expected to integrate the risks associated with climate change in their long-term planning should depend on the circumstances unique to each utility. In that regard, the Company faces an enhanced obligation to integrate climate change into its long-term planning, given the extent to which the financial community has identified the Company as one of the electric utilities in the country with the greatest exposure to climate change impacts. Thus, the Company's failure to integrate such impacts into its analysis affects not only the level of operating costs it incurs over time, but also the capital costs borne by its customers to the extent that the financial community perceives that the Company is doing a poor job of managing those risks, and accordingly demands a higher cost of capital for the costs of financing the Company's investments.

Q. Are you aware of any processes underway in North Carolina that would enable the Company to use existing climate science and climate analytics to inform its decision making?

A. Yes. As noted above, there is a current proceeding at the North Carolina Department of Environmental Quality—Phase 2 of the climate risk and resilience group—that is relevant to the type of analysis that should be required of the Company going forward. NCICS has performed a high-value granular analysis of likely climate conditions in North Carolina through the remainder of the century (publication pending). Through funding from the US Department of Energy, the North Carolina State Clean Energy Technology Center is hosting a collaborative process that is going to look precisely at this issue.

Q. Would it be reasonable for the Company to use the data and expertise gathered from these various working groups to inform its own system planning process with the best available climate science and scenario analysis techniques?

A. Yes. In fact, it would be unreasonable, and inconsistent with prudent utility practice, for the Company to fail to incorporate these resources to help prioritize strategies and investments to improve the resilience of the Company's network in the face of increasing risks from climate change.

Q. Did the Company perform any forward-looking analysis of climate-related data to inform its recommended GIP investments?

A. No. As described in the preceding section, the Company failed to take into account what we currently know about possible scenarios regarding temperature, humidity, precipitation, and sea level increases over time. It is irresponsible, and contrary to prudent utility practice, to base long-term planning on historical trends that simply do not reflect the new reality of the impacts of climate change going forward. And the consequence of this failure would be to impose unnecessary costs on the Company's customers, which would be disallowed in the typical ratemaking process. The better outcome than relying on the end-loaded disallowance, of course, is to require the Company to engage in a rigorous planning process that integrates the impact of climate change.

Q. Does this mean the Company's GIP fails to carry the burden of proof at this time?

A. There is insufficient data available to determine if the Company made the most prudent prioritization and investments in light of its actual, projected climate risk. However, the failure to even attempt to quantify and identify its climate vulnerabilities, in our view, dramatically increases the risk that these investments could prove more costly to ratepayers over time than investments made under a strategy that diligently considered and mitigates future climate vulnerabilities.

Q. If you are not recommending a current disallowance based on the Company's failure to consider climate risk, why should the Commission consider climate risk as a necessary consideration to justify the prudency of these types of climate-vulnerable infrastructure investments going forward?

A. The risks are intensifying and the impacts are growing. The need to mitigate to be cost-effective is growing. The visibility and confidence level of future climate data are growing. Based on the standard of doing what a reasonable manager would do based on what they know or *should know*, willful blindness to the reality of climate change going forward cannot be a defense. The Company simply must do better if it is to fulfill its fundamental obligation to engage in practices that result in the lowest costs to its customers over time.

D. Incentive Mechanisms to Encourage Integration of Climate-Related Risks

Q. How can the Company be encouraged to integrate climate-related risks into its long-term system planning?

A. As noted above, the Commission has considerable discretion in deciding whether or not to authorize deferred accounting treatment for the Company's GIP. The Commission previously rejected deferred accounting treatment for the Company's proposed Power Forward program, which in many ways is replicated by the Company's proposal in this case with respect to the GIP. Notwithstanding the similarities, the Commission has the authority to address any perceived deficiencies through a properly structured incentive mechanism. We recommend consideration of a performance-based incentive mechanism that would properly penalize or reward the Company for integrating climate change-related risks into its long-term system planning.

Q. What are the elements of this performance-based incentive mechanism?

A. As noted earlier in this testimony, the Company is seeking to defer the investment and costs related to its GIP, and to earn a return equal to its weighted average cost of capital ("WACC") on the unamortized balance. The Commission has the discretion to determine whether or not to grant the Company's deferral request and, correspondingly, has the authority to impose conditions on granting that request. We recommend that the Company's ability to earn its WACC on the unamortized balance of GIP investments be subject to a performance-based incentive mechanism. In other words, the extent to which the Company is allowed to earn its WACC should be a function of its success in integrating climate change-related risks into its GIP. We propose that the portion of the WACC be weighted according to the Company's success in achieving certain prescribed metrics that reflect the integration of climate change-related risks into long-term system planning.

Q. How would such an incentive mechanism operate?

A. If the Company does a good job of meeting such metrics, it would be allowed to earn its WACC on the unamortized balance. If the Company falls short, the return it is allowed to earn on the unamortized balance would be less than its WACC. To make the incentive mechanism symmetrical, the Company should have an opportunity to earn a return greater than its WACC. In other words, the Company should be rewarded to the extent that it does an exemplary job of integrating climate change-related risks, and could earn a return in excess of its WACC upon exceeding the prescribed metrics.

Q. Is there precedent for such a performance-based mechanism?

A. Yes. Under the Future Energy Jobs Act passed by the Illinois legislature in December 2016, electric utilities in that state have the option of capitalizing the investment they make in energy efficiency measures, and to amortize such investment over the measures' useful lives. The return they earn on the unamortized balance of such investments is subject to performance-based metrics that capture the utilities' respective performance in achieving energy efficiency savings. The performance-based incentives under the Future Energy Jobs Act operate to reward utilities for exceeding their energy efficiency savings targets and to impose penalties if they fall short.[196] Another example is the use of earnings adjustment mechanisms by the New York Public Service Commission as part of its Reforming the Energy Vision ("REV") programs. Under the "Track Two" Order in the REV proceeding, a utility can be provided with incentives up to the dollar equivalent of 100 basis points of its return on equity based on its ability to implement various measures that are consistent with REV objectives, such as facilitating interconnection of DERs, increasing electric usage intensity (i.e. reducing peak and improving load factor), encouraging customer engagement, and implementing beneficial electrification programs (e.g., heat pumps) geared toward greenhouse gas reductions.[197]

Q. What sort of metrics could be included in such a mechanism to capture the Company's integration of climate change-related risks?

A. There are several measures that would reflect the improvement in the resilience of the Company's network in the face of climate change risks, such as (1) improvements in reliability-related statistics (e.g., SAIDI, SAIFI, or MAIFI), (2) hosting capacity for DERs (measured in kWs), (3) voltage reductions (measured as average annual voltage by circuit), (4) demand response from time-varying rates (measured in kWs), (5) participation in time-varying rates (as a percentage of

[196] The Future Energy Jobs Bill (SB 2814) was enacted into law on December 7, 2016, as Public Act 99-0906, with an effective date of June 1, 2017.
[197] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (May 19, 2016), pp. 53-93.

customers), or (6) operational savings, measured in dollars or dollars per average bill. These metrics would capture the sort of benefits that one should expect from large investments in the Company's grid. These performance targets should be quantifiable, not subjective; should include achievement dates; and be based on outcomes, not processes.

Q. How would this mechanism and these metrics be established?

A. The details regarding the design of such a mechanism are beyond the scope of this proceeding, and should be considered in a subsequent proceeding on comprehensive and integrated grid planning. The record in this case would simply not support a thorough evaluation consideration of these issues, which would benefit from a full examination by all the interested stakeholders.

7. CLIMATE RISK AND CUSTOMERS

Q. How do customers figure into the discussion of utilities and climate risk?

A. Customers are directly affected by the impacts of climate-related physical risks, with respect to both the quality/reliability of their service and the costs of that service. Upon the occurrence of an extreme weather event, customers' electric service is subject to interruption for extended periods. Actions by the utility to improve the resilience of the grid thus should reduce the adverse impacts on service arising from extreme weather events. Similarly, integration of climate change-related risks in the utility's long-term system planning should result in lower costs for customers over time, as the utility will avoid or minimize investments in facilities that are vulnerable to extreme weather events, thereby minimizing the storm damage costs that ultimately are recovered in utility rates. The extent to which utilities engage in resilience-related investments to reduce their climate-related risks thus redound to the benefit of customers.

Q. Are there particular groups that are expected to be more vulnerable to the electric service-related impacts of climate change?

A. Climate adaptation and vulnerability studies show that the most socially vulnerable households today often bear the most exposure to climate-related risks.[198] These

[198] Lynn, K., MacKendrick, K., & Donoghue, E., (2011, August). Social Vulnerability and Climate Change: Synthesis of Literature. *US Forest Service.* Retrieved at: https://www.fs.fed.us/pnw/pubs/pnw_gtr838.pdf;
U.S. Global Change Research Program (2016). The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. *Populations of Concern.* Retrieved at: https://health2016.globalchange.gov/populations-concern.

households often lack access to resources necessary to cope with climate-related shocks and stresses. Specifically, low-income households and communities of color[199]—commonly referred to as "environmental justice communities"—and those at home who are medically dependent on electricity[200] are especially likely to be vulnerable to climate-related risks. Thus, the consequences of a utility's failure to integrate climate change-related risks into its long-term system planning will fall disproportionately on segments of the population least capable of coping with the impacts.

Q. Are there potential customer programs that the Company could pursue through ISOP, or otherwise, that could address the needs of their most vulnerable customers and communities?

A. Yes. As discussed above, DERs have unique resilience benefits in that they can generate energy closest to where it is needed. With the right kind of forward-looking planning, DERs could be deployed through ISOP or other resource planning proceedings to equip these communities with the assets and resources to withstand climate-related risks. Some examples of potential programs could be storage "resilience hubs" in vulnerable neighborhoods, or behind-the-meter solar plus storage programs for medically vulnerable ratepayers.

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[199] Coffee, J. (2018, February). Climate Disasters Hurt the Poor the Most. Here's What We Can Do About it. *Governing.* Retrieved at: https://www.governing.com/commentary/col-disasters-disadvantaged-climate-justice.html.

[200] Dominianni, C., Ahmed, M., Johnson, S., Blum, M., Ito, K., Lane, K., (2018, July). Power Outage Preparedness and Concern among Vulnerable New York City Residents. *Journal of Urban Health.* Retrieved at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6181821/.

Q. What are your recommendations to protect customers, and in particular low-income customers, from the rate impacts associated with climate change-related risk and grid resiliency strategies going forward?

A. Ultimately, prudent management of climate-related risks by the utility should produce the desired effect of minimizing rate impacts of climate-related risks and, to the extent such risks are not managed prudently, regulators have a responsibility to ensure that imprudent costs are not passed on to customers, whether low-income or not. The Commission is uniquely situated to exercise its full range of options to minimize rate impacts through, among other things, the period over which grid resilience investments are amortized or how such costs are allocated to customer classes.

Targeted climate resilience investments could also provide relief for low-income customers. Solar plus storage investments, for example, could decrease bills while ensuring resilience against climate impacts. Equitable access to such measures, of course, is a challenge, and the Commission may wish to focus particular attention to developing programs that facilitate access to such investments by environmental justice communities.

8. CONCLUSIONS AND RECOMMENDATIONS

Q. Based on your review of the Company's filing and emerging electric utility trends, what conclusions do you reach in this testimony?

A. We reach the following conclusions:

- Climate-related risks, emerging in many vectors, have a material and substantial bearing on the Company's operations today and will continue to affect operations in the future. Collaborative processes in North Carolina are currently underway to assess these risks and their implications for the electric grid.
- The Company faces demonstrable physical risks from climate change and increasing scrutiny on climate risk management from relevant financial institutions.
- As a potential foundational investment for the 21st century grid, any grid modernization plan should consider best climate resilience practices alongside grid modernization best practices. This includes the fair assessment of DERs as climate resilience and grid modernization solutions.
- The Grid Improvement Plan, as filed, does not assess or respond to climate-related risks, nor does it adhere to grid modernization best practices. As a result, the Company's proposal does not provide enough information to indicate that the Plan is a prudent investment.

Q. Based on your review of the Company's filing and emerging electric utility trends, what recommendations do you make in this testimony?

A. We respectfully ask that the Commission:

- Direct the Company to assess and manage climate-related risks across its operations and assets, in accordance with prudent utility practice.
- Make clear that it will hold the Company accountable for implementing this standard when it evaluates the prudence of proposed GIP investments by the Company.
- Direct the Company to participate in ongoing Department of Environmental Quality stakeholder processes around grid modernization and integrate data, findings, and recommendations, into its grid modernization investments. The Commission should further require that the Company file a report by December 31, 2020 identifying any gaps in knowledge that need to be filled through further collaboration.
- Require the Company to develop large distribution investments such as the GIP through an integrated distribution planning ("IDP") or integrated systems & operations planning ("ISOP") process moving forward.
- To the extent that GIP projects are permitted deferred recovery, impose performance-based conditions on the recovery of such deferred amounts in rates, such as through adjustments to the weighted average cost of capital applied to the unamortized balance of deferred amounts.

Q. Does this conclude your testimony?

A. Yes.

COMMISSIONER CLODFELTER: All right. That brings me to Mr. Quinn, you're next. NC WARN.

(No response.)

COMMISSIONER CLODFELTER: Mr. Quinn, did I lose you? Mr. McCoy, do you have Mr. Quinn anywhere?

MR. McCOY: Commissioner, he's not here.

COMMISSIONER CLODFELTER: All right. We will come back to NC WARN. I know he had evidence he needed to move in, so I'm going to take him out of order later in the case if we need to do so.

Harris Teeter?

MR. BOEHM: Good morning, Commissioner Clodfelter. Harris Teeter --

COMMISSIONER CLODFELTER: There you are. Great. I've got you now.

MR. BOEHM: Good morning. We moved our testimony of our witness in the consolidated case a couple weeks ago.

COMMISSIONER CLODFELTER: That's correct. So you're good to go. Again, I just want to be on the safe side here.

(Exhibits JDB-1 through JDB-3 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct testimony of Justin Bieber was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITY COMMISSION

Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**DOCKET NO. E-2 SUB 1219**

DIRECT TESTIMONY OF

JUSTIN BIEBER

ON BEHALF OF

HARRIS TEETER LLC

April 13, 2020

DIRECT TESTIMONY OF JUSTIN BIEBER

Introduction

Q. Please state your name and business address.

A. My name is Justin Bieber. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Senior Consultant for Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Harris Teeter LLC. ("Harris Teeter"). Harris Teeter is one of the largest retail grocers in North Carolina and operates 43 facilities that are served by Duke Energy Progress, LLC ("Duke Energy Progress" or the "Company"). Combined, Harris Teeter facilities purchase approximately 100 million kWh annually from Duke Energy Progress.

Q. Please describe your professional experience and qualifications.

A. My academic background is in business and engineering. I earned a Bachelor of Science in Mechanical Engineering from Duke University in 2006 and a Master of Business Administration from the University of Southern California in 2012. In 2017, I completed Practical Regulatory Training for the Electric Industry sponsored by the New Mexico State University Center for Public Utilities and the

National Association of Regulatory Utility Commissioners. I am also a registered Professional Civil Engineer in the state of California.

I joined Energy Strategies in 2017, where I provide regulatory and technical support on a variety of energy issues, including regulatory services, transmission and renewable development, and financial and economic analyses. I have also filed and supported the development of testimony before various different state utility regulatory commissions.

Prior to joining Energy Strategies, I held positions at Pacific Gas and Electric Company as Manager of Transmission Project Development, ISO Relations and FERC Policy Principal, and Supervisor of Electric Generator Interconnections. During my career at Pacific Gas and Electric Company, I supported multiple facets of utility operations, and led efforts in policy, regulatory, and strategic initiatives, including supporting the development of testimony before and submittal of comments to the FERC, California ISO, and the California Public Utility Commission. Prior to my work at Pacific Gas & Electric, I was a project manager and engineer for heavy construction bridge and highway projects.

Q. Have you testified previously before this Commission?

A. Yes, I testified in Duke Energy Progress' 2017 general rate case, Docket No. E-2, Sub 1142 and Duke Energy Progress' 2019 general rate case, Docket No. E-7, Sub 1214.

Q. Have you filed testimony previously before any other state utility regulatory commissions?

A. Yes. I have testified before the Colorado Public Utilities Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Montana Public Service Commission, the Public Utilities Commission of Ohio, the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Public Service Commission of Wisconsin.

<u>**Overview and Conclusions**</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the following topics:

- Rate design for the SGS-TOU rate schedule,
- The Company's proposal to defer Grid Improvement Plan costs in a regulatory asset, and
- A multi-site commercial rate aggregation pilot.

Q. Please summarize your recommendations to the Commission.

I offer the following recommendations for the Commission:

- Duke Energy Progress' proposed rate design for the SGS-TOU rate schedule significantly understates demand related charges while overstating the energy charges relative to the underlying cost components, based on the Company's own cost of service study. In fact, the proposed rate design in this case would actually *worsen* the existing misalignment between SGS-TOU charges and cost causation relative to current rates. I recommend modifications to the proposed SGS-TOU rate design that will improve the alignment between the rate components and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts.

- The Commission should reject the Company's proposal to defer certain investment costs associated with Duke Energy Progress' Grid Improvement Plan in a regulatory asset. The proposed deferral is unnecessary and future recovery of the deferred costs would amount to single-issue ratemaking that does not address a compelling public interest or meet the generally accepted criteria for this type of regulatory treatment. Recovering costs in this manner would provide expanded cost recovery for Grid Improvement Plan costs without consideration of whether the Company could experience offsetting decreases in expenses or increases in revenues in other areas.
- It is reasonable and appropriate at this time for the Company to initiate a multi-site commercial rate aggregation study in order to provide an opportunity for the Company and its stakeholders to gain insight into how a multi-site aggregation rate would work. A well-designed demand aggregation program places a customer with multiple locations on an equal footing with single-site customers, by charging participating multi-site customers for the amount of

generation and transmission services that they actually use, thereby promoting equitable treatment of these customers. To that end, I recommend that the Commission order the Company to study the feasibility of multi-site aggregate commercial rate and propose a pilot program it its next rate case that would allow commercial customers to participate in a multi-site rate applicable to the portion of the demand charge associated with fixed production costs.

SGS-TOU Rate Design

Q. Please describe Duke Energy Progress' SGS-TOU rate schedule.

A. Duke Energy Progress' SGS-TOU rate schedule is a time of use rate schedule that is generally available to customers with an initial Contract Demand between 30 kW and 1,000 kW. The current SGS-TOU rate schedule consists of a basic customer charge, summer and winter on-peak demand charges, an off-peak excess demand charge, and on-peak and off-peak energy charges.

Q. Please explain how Duke Energy Progress has proposed to modify the SGS-TOU rates in this proceeding.

A. According to Duke Energy Progress' rate design witness Michael Pirro, the proposed Customer Charge is unchanged for this rate schedule, while the demand and energy charges are increased by the same percentage to achieve the target revenue requirement. Mr. Pirro explains that marginal cost continues to support the current seasonal time of use price relationships. The proposed summer on-peak demand rate continues to exceed the non-summer rate by 19%, while the on-peak energy rate continues to exceed the off-peak energy rate by 23.4% to incent load shifting to off-peak hours.[1]

Table JDB-1 below summarizes the Company's current and proposed rates for the SGS-TOU rate schedule at the Company's proposed revenue requirement and revenue allocation.

Table JDB-1
DEP Present and Proposed SGS-TOU Rates

Charge	Current Rate	Proposed Rate	Increase %
Basic Customer Charge	$35.50	$35.50	0.0%
Energy Charges On-peak	$0.06460	$0.07100	9.9%
Energy Charges Off-peak	$0.05235	$0.05754	9.9%
Demand Charges Summer	$10.53	$11.58	10.0%
Demand Charges Non-Summer	$8.85	$9.73	9.9%

Q. The SGS-TOU rate schedule is a time of use rate schedule. Please explain why this is significant.

A. Time of use rates should be designed to send proper price signals to customers to incentivize the efficient use of grid assets. Customers who choose a time-of-use rate are more likely to be responsive to price signaling. Therefore, it is even more important for time of use rate designs to align with cost causation, so that customers who choose to be on a time of use rate are rewarded for using the grid more efficiently. The most efficient use of grid assets is incentivized if energy and demand charges are aligned with their underlying costs.

[1] Direct Testimony of Michael J. Pirro, pp. 19-20.

Q. What is your assessment of Duke Energy Progress' proposed rate design for the SGS-TOU rate schedule?

A. Duke Energy Progress' proposed rate design for the SGS-TOU rate schedule significantly under-recovers the demand-related charges while over-recovering the energy-related charges relative to the underlying costs based on the Company's proposed 1 coincident peak ("1 CP") cost of service study. This results in a significant misalignment between the rate design charges and the underlying cost causation. In fact, the proposed on-peak energy charge is 85% greater than the embedded unit cost for the SGS-TOU schedule while the proposed off-peak energy charge is 50% greater than the unit cost. At the same time, the proposed summer on-peak demand charge is only 64% of the embedded unit cost, while the non-summer on-peak demand charge is just 54% of the embedded unit cost. Table JDB-2 below compares the Company's proposed charges to the embedded unit costs.

Table JDB-2
DEP Proposed Charges Relative to Embedded Unit Costs[2]
For the SGS-TOU Rate Schedule

Charge	Proposed Rate	Embedded Unit Cost	Charge/Cost
Basic Customer Charge	$35.50	$41.06	86.5%
Energy Charges On-peak	$0.07100	$0.03834	185.2%
Energy Charges Off-peak	$0.05754		150.1%
Demand Charges Summer	$11.58	$18.15	63.8%
Demand Charges Non-Summer	$9.73		53.6%

[2] Embedded unit costs for the SGS-TOU rate schedule based on the Company's 1 CP cost of service study provided in Duke Energy Progress' response to Harris Teeter Data Request No. 3-1, reproduced in Exhibit JDB-1.

Q. Does DEP's proposed SGS-TOU rate design make any movement towards improving the alignment between the charges and the underlying costs?

A. No, it does not. In fact, it actually exacerbates the existing misalignment between the charges and the underlying embedded costs. Based on the Company's 1 CP cost of service study, the proposed demand related costs for the total Medium General Service rate class ("MGS")[3] increase by 25.8%[4] in this case, while the energy related costs only increase by 2.4%.[5] However, the Company's proposed SGS-TOU rate design would increase both the energy and demand charges by approximately 9.9%. Increasing the energy and demand rate elements by the same percentage, when the overwhelming majority of the proposed increase in costs is demand related, would result in rates that are further misaligned with the underlying cost causation relative to the current rate design.

Q. Does the Company's proposed SGS-TOU rate design reflect the marginal costs on a directional basis?

A. No, it does not. The marginal energy costs are actually even lower than embedded energy costs, while the marginal demand costs are substantially higher than the embedded demand costs. On a directional basis, these marginal system energy and demand costs also indicate that the Company's proposed SGS-TOU energy and demand charges would *worsen* the existing misalignment between the

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[3] The MGS rate class includes the SGS-TOU rate schedule. However, Duke Energy Progress did not provide a unit cost study with the SGS-TOU rate schedule broken out at the proforma adjusted present rates cost of service.
[4] Duke Energy Progress Response to E1 Item #45 1CP 2018 Adj Pres Unit Costs and 1CP 2018 Adj Prop Unit Costs. Proposed demand unit cost \$19.05/kW ÷ current demand unit cost \$15.14/kW – 1 = 25.8%.
[5] Id. Proposed energy unit cost 3.85 ¢/kW ÷ current energy unit cost 3.76 ¢/kW – 1 = 25.4%.

charges and underlying cost causation. Table JDB-3 below compares the marginal unit costs to the SGS-TOU embedded costs and proposed rates.

Table JDB-3
Marginal Costs[6] Relative to Embedded Unit Costs and Proposed Rates
For the SGS-TOU Rate Schedule

Charge	**Proposed Rate**	**Embedded Unit Cost**	**Marginal Unit Cost**
Energy Charges On-peak	$0.07100	$0.03834	[redacted]
Energy Charges Off-peak	$0.05754		
Demand Charges Summer	$11.58	$18.15	[redacted]
Demand Charges Non-Summer	$9.73		

*Total system marginal cost of distribution and transmission

Q. From a customer's perspective, why should it matter if Duke Energy Progress proposes a demand charge that does not fully recover its demand-related costs?

A. If a utility proposes a demand charge that is below the cost of demand, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case with Duke Energy Progress' proposed rate design. For a given rate schedule such as SGS-TOU, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors are required to subsidize the lower load factor customers within the class.

[6] Duke Energy Progress Confidential Response to Form E-1 Data Request, Item 40 Marginal Cost Review. The marginal energy cost is for years 2018-2022. The marginal system distribution cost for 2020 is $[redacted]/kW. The marginal system transmission cost for year 2020 is $[redacted]/kW.

Q. How do you define higher load factor customers?

A. For purposes of this discussion, I use this term to refer to customers whose load factors are greater than the average for the rate schedule.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with cost causation is important for ensuring equity among customers, because properly aligning charges with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere — typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. Does the Company recognize the importance of aligning rate design with the underlying costs?

A. Yes, it does. According to Mr. Pirro, setting rates that are aligned with the underlying unit cost minimizes cross-subsidization within a rate class and provides appropriate price signals to customers regarding the true cost impact of their usage.[7]

Q. What is your recommendation with respect to the SGS-TOU rate design?

A. I recommend moderate changes to the proposed SGS-TOU energy and demand charges that will make some progress towards aligning the rate design with the underlying costs while also mitigating the intra-class rate impacts that would result from a more significant movement towards cost-based rates at this time. Specifically, I recommend that the SGS-TOU summer and non-summer on-peak demand charges should be increased by the amount necessary to recover the final SGS-TOU revenue target while maintaining the current on-peak and off-peak energy rates. I am not recommending any changes to the Company's proposed customer charge, off-peak excess demand charges, or minimum bill charges. Nor am I recommending any changes to the Company's proposed seasonal and on-peak/off-peak time of use relationships. The revenue verification for this rate design is presented in Exhibit JDB-2. The proposed rates are summarized in Table JDB-4 below.

[7] Direct Testimony of Michael J. Pirro, p. 11.

Table JDB-4
DEP and Kroger Proposed SGS-TOU Rates
At DEP's Proposed Revenue Requirement

Charge	Current Rate	DEP Proposed Rate	Kroger Proposed Rate
Basic Customer Charge	$35.50	$35.50	$35.50
Energy Charges On-peak	$0.06460	$0.07100	$0.06460
Energy Charges Off-peak	$0.05235	$0.05754	$0.05235
Demand Charges Summer	$10.53	$11.58	$14.13
Demand Charges Non-Summer	$8.85	$9.73	$11.88

Q. How does your recommended rate design improve the alignment between charges and the underlying cost components?

A. As I describe above, the Company's proposed rate design for the SGS-TOU rate schedule significantly under-recovers the demand-related charges while significantly over-recovering the energy-related charges. Given that the current energy charges are already significantly above the embedded and marginal unit costs, while the current demand charges are substantially less than the embedded and marginal unit costs, my proposal to maintain the current energy charges while increasing the demand charges makes *gradual* movement towards improving the alignment between the demand and energy revenues and costs.

Q. Does your proposed rate design result in charges that are 100% aligned with costs?

A. No, it does not. As I explain above, I am proposing modest changes the SGS-TOU rate design that result in gradual movement towards aligning rates with the underlying cost causation in order to mitigate the intra-class rate impacts that could result from a more significant movement towards cost-based rates at this time. In fact, under my proposed SGS-TOU rate design, the on-peak energy charge would still be *68% greater* than the embedded unit cost while the off-peak energy charge would be *37% greater* than the embedded unit cost. Thus, a substantial portion of the SGS-TOU demand related costs would continue to be recovered through the energy charges.

Q. Do you have an alternative recommendation if the Commission determines that a more gradual movement towards aligning rates with the underlying costs is appropriate?

A. As I explain above, I am already recommending a *gradual* movement towards improving the alignment between the demand and energy revenues and costs. However, to the extent the Commission determines that an even more gradual improvement is appropriate, then I recommend that the SGS-TOU on-peak and off-peak energy charges should be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU revenue target. The summer and non-summer demand charges can be increased by an equal percentage amount necessary to recover the remainder of the approved revenue target. Increasing the energy charges by a lower percentage than the percentage increase to the demand charges would at least result in *some* movement towards cost, relative to the Company's proposed rates.

Q. Have you prepared a rate impact analysis of your recommended changes to the SGS-TOU rate design?

A. Yes. My rate impact analysis is presented in Exhibit JDB-3 and illustrates the total bill impacts to customers that would result from my recommended SGS-TOU rate design at the Company's proposed revenue requirement. The base rate bill impacts for the various customer load profiles I have included in my analysis range between 7.4% and 12.3%, relative to the Company's proposed overall increase of 10.3% for the SGS-TOU class.

Q. Please explain why the customer load profiles that you analyzed in Exhibit JDB-3 differ from the customer load profiles analyzed by the Company for this purpose.

A. The customer load profiles that the Company utilizes in Exhibit Pirro No. 3 to assess the SGS-TOU rate impacts are not representative of the SGS-TOU class of customers. Half of the customer load profiles analyzed have on-peak billing demands that are 25 kW or less. However, the SGS-TOU rate schedule is typically available to customers with maximum loads between 30 kW and 1,000 kW. Therefore, I modified the selection of customer load profiles for my bill impact analysis to include profiles with monthly billing demands at either 85 kW or 600 kW with corresponding load factors that range from 40% to 80%. These profiles assess a range of customer loads that is generally centered around the average usage characteristics for the class and wide enough to provide visibility to the varying degree of impacts to both high and low load factor customers.

Q. Your proposed rate design results in a slightly smaller rate impact on higher-load-factor customers than lower-load-factor customers. Is this a reasonable result?

A. Yes, it is a reasonable result. My proposed rate design reflects a cost-based difference while providing gradual movement towards cost-based rates. Duke Energy Progress' proposed rate design contains a significant misalignment between the underlying costs and charges based on its own cost of service study, which results in an intra-class subsidy from higher-load-factor customers to lower-load-factor customers.

As I state above, I am not proposing full movement towards cost-based rates in this case. Instead, my proposed rate design makes *gradual* movement towards aligning rates with cost causation and reduces, but does not eliminate, the existing intra-class subsidy. By gradually reducing this intra-class subsidy, lower-load-factor customers will experience slightly greater rate increases than higher-load-factor customers. This is a reasonable result because it strikes a balance between two important rate-making principles – improving the alignment between rates and the underlying cost components while employing gradualism.

Q. In response to discovery, the Company has expressed concerns that aligning rates purely based on unit costs could invalidate the SGS-TOU rate design because there is a misalignment between the demands used in the cost of service study and rate design billing determinants.[8] Can you please explain the Company's concern?

A. In response to discovery on this topic, the Company explains that the cost of service study utilizes summer coincident peak demand to allocate production and transmission related costs and noncoincident demands to allocate the demand portion of distribution plant, while the rate design billing determinants are based on the noncoincident peak. According to the Company, using noncoincident demands as a "common denominator" dilutes the other demand elements. The result of such

[8] Duke Energy Progress response to Harris Teeter Data Request No. 4-3, reproduced in Exhibit JDB-1.

dilution is that high load factor customers who have higher coincidence with the system peak as load factor increases, can drive their costs below the actual cost of providing service.[9]

Q. Can you please describe what it means for a customer to have a higher coincidence with the system peak?

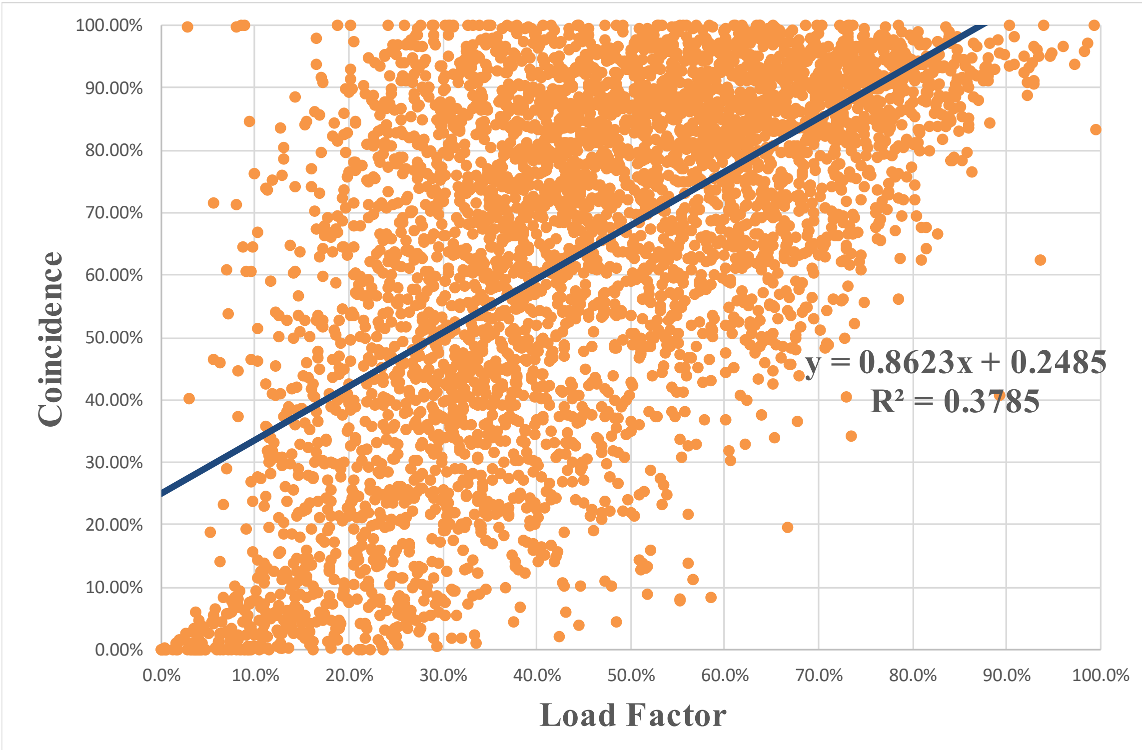
A. The coincidence with system peak is equal to the customer's load at the time of system peak divided by the customer's maximum billing demand. For example, consider two customers with identical monthly billing demands of 100 kW. Customer 1's maximum load of 100 kW occurs at the same time as the system peak, so its coincidence factor is 100%. However, Customer 2's maximum load of 100 kW occurs at an off-peak time. At the time of the system peak, Customer 2's load is only 50 kW, so its coincidence factor is 50%. Both customers have the same maximum load, but different coincidences with the system peak. Customer 1's load which is 100% coincident with the system peak places a higher burden on the system than Customer 2's load which is only 50% coincident with the system peak.

Q. Do customers with higher load factors also have higher coincidence factors?

A. Not necessarily. Chart JDB-1 below is a plot of the monthly coincidence factor vs. load factor for the load sample of customers utilized by the Company in its SGS-TOU Rate Design Model.

[9] Id.

Chart JDB-1
SGS-TOU Monthly Coincidence vs. Load Factor[10]



While there is a positive linear correlation between the load factor and coincidence factor, it is a weak correlation with a coefficient of determination, or R-Squared value equal to 0.3785. It is clear from this diagram that there are many instances where customers with high load factors have high coincidence with peak, but there are also many instances where customers with low load factors also have a high coincidence with the system peak.

[10] Duke Energy Progress Confidential Response to North Carolina Public Staff Data Request No. 69-3, Attachment PSDR 69-3 SGS-TOU Rate Model, reproduced in Exhibit JDB-1.

Q. How would you respond to the Company's concern that a cost-based rate structure would allow a high load factor customer who has a high coincidence with system peak to drive its rates below cost?

A. The Company asserts that if energy and demand are 100% aligned with cost, then an *individual* high load factor customer who has higher coincidence with the system peak can drive its costs below the actual cost of providing service. However, the same is true for a low load factor customer who also has a high coincidence with the system peak. It is well accepted in ratemaking that no rate design can precisely match all individual customers' cost recovery with the actual cost to serve for a rate schedule that serves a large number of customers. And, there is only a weak correlation between load factor and coincidence factor for the SGS-TOU rate schedule.

Further, as I explain above, lower-load-factor customers are already receiving a subsidy from higher-load-factor customers due to the existing misalignment between rates and the underlying costs. Since I am only recommending gradual improvement to the alignment between charges and costs, lower-load-factor customers who have a lower coincidence with system peak will continue to receive a portion of this subsidy currently being paid by higher-load-factor customers.

Q. Is distorting the SGS-TOU rate design to include fixed costs in the energy charge an effective tool to incentivize energy conservation?

A. It is sometimes argued that including demand related costs in the energy charge can incentivize the conservation of energy. I disagree that intentionally distorting rate design is an effective means to accomplish energy conservation related goals. The primary goal of energy conservation efforts is to reduce the use of fossil fuels and the related emissions and byproducts. Properly considering the external and societal costs of fossil fuels in generation planning and dispatch decisions, and allocating those costs through a cost of service study, is the appropriate and more effective method to accomplish energy conservation goals. As I explain above, aligning rates with the underlying costs will send more efficient price signals to customers that reflect the true cost of their consumption. This will become even more important in the future, especially as many older fossil fuel generation resources are retired and renewable resources like solar and wind, with high fixed costs and low variable costs, provide a much larger share of our energy needs.

Q. Is there a potential for customers to migrate between the MGS and SGS-TOU rate schedules?

A. Whenever there are multiple rate schedule options for customers with the same usage characteristics, such as the case for the MGS and SGS-TOU rate schedules, there is the potential that some customers that were better off on one schedule under the old rates would actually be better off on a different rate schedules under the new rates. When this happens, customers may migrate between rate schedules.

Q. Has the Company performed a migration analysis for the MGS and SGS-TOU classes in this case?

A. No, it has not. According to the Company, it did not perform a migration analysis in this case because the Company does not expect any additional migration between the MGS rate schedule and the SGS-TOU rate schedule, since the rate design was not expected to change the breakpoint where customers are better off on the MGS versus the SGS-TOU rate schedule.[11]

Q. Has the Company conducted any recent studies to determine under the current rates whether any SGS-TOU or MGS customers would be better off if they migrated to the other rate schedule?

A. No. According to the Company's response to discovery, it has not conducted this type of study in recent years.[12]

Q. What is the breakpoint or load factor where customers are better off on the MGS versus the SGS-TOU rate schedule?

A. According the Company, customers whose load factors are 30% and below are usually better off on the MGS rate schedule as compared to the SGS-TOU rate schedule.[13]

Q. What is the average load factor for the MGS rate schedule?

A. I have calculated the average load factor for the MGS rate schedule for the test year to be 29.6%.[14]

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[11] Duke Energy Progress Response to Harris Teeter Data Request No. 2-4, reproduced in Exhibit JDB-1.
[12] Duke Energy Progress Response to Harris Teeter Data Request No. 5-1, reproduced in Exhibit JDB-1.
[13] Id.
[14] MGS Load Factor = Avg. Monthly Energy Usage per Customer 14,081 kWh ÷ Avg. Monthly Billing Demand per Customer 65 kW ÷ 730 hours/month = 29.6%

Q. What is your assessment of the breakpoint load factor between the MGS and SGS-TOU rate schedules?

A. The average MGS load factor is 29.6%, which is approximately equal to the break point load factor of 30%. This indicates that a substantial number of current MGS customers, with above average load factors relative to the rest of the class, would actually be better off if they migrated to the SGS-TOU rate.

Q. What is your assessment of the potential migration risk under your proposed rate design?

A. Depending on the final revenue targets for the MGS and SGS-TOU rate schedules, my proposed rate design could increase the break point load factor by a few percent. However, there is already a substantial amount of load on the MGS rate schedule that would be better off migrating to the SGS-TOU rate schedule. If the break point load factor increased by a few percent, that would actually reduce potential migration because there would be significant load on the MGS rate schedule for which it would no longer be beneficial to migrate to the SGS-TOU rate. Given this substantial potential for my proposed rate design to offset migration from the MGS rate schedule, and the Company's lack of migration analyses, I recommend that the Commission find that no migration adjustment is necessary to provide the Company a sufficient opportunity to realize the approved revenue requirement.

However, to the extent that the Commission does determine that a migration adjustment is necessary to implement my proposed rate design, then I recommend that the Commission approve a migration adjustment to be allocated to the MGS rate schedule, designed to avoid the potential migration of customers from the SGS-TOU class. Maintaining customers on the SGS-TOU rate schedule, while improving the alignment between charges and costs as I have proposed, would result in more efficient price signals for a greater number of customers.

Q. Would your proposed rate design result in better revenue stability for the Company?

A. Yes, it would. In general, energy usage is more volatile than billing demand. Therefore, increasing the proportion of revenues that are recovered through demand charges would result in increased revenue stability for the SGS-TOU rate schedule.

Q. Your proposed SGS-TOU rate design was calculated using the Company's proposed revenue requirement. How should your proposed rate design be implemented if the Commission adopts a base rate revenue requirement that is different than Duke Energy Progress' request?

A. To the extent that the Commission approves a revenue target for the SGS-TOU rate schedule that is different than that proposed by Duke Energy Progress, I recommend that the summer and winter on-peak demand charges and the on-peak and off-peak energy charges that I have proposed each be reduced by an equal percentage in order to recover the target revenue requirement.

<u>Grid Improvement Plan Accounting Deferral</u>

Q. Please describe Duke Energy Progress' proposal to recover costs related to the Grid Improvement Plan investments.

A. Company witness Kim Smith explains that the proposed new rates in this proceeding include recovery of Grid Improvement Plan expenditures that are included in the Test Period, as well as supplemental updates for post Test Period plant additions. In addition, the Company is requesting permission to defer costs related to its Grid Improvement Plan, that are not included in this case, in a regulatory asset for cost recovery consideration in future general rate cases. The Grid Improvement Plan is a three-year plan spanning calendar years 2020 through 2022.[15]

Q. What specific costs does the Company propose to defer?

A. Ms. Smith explains that there are thirteen Distribution programs, three Transmission programs, and five Enterprise programs included in the Grid Improvement Plan. The Company is requesting deferral of North Carolina retail's share of depreciation on capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, operations and maintenance expense related to the installation of equipment, property tax related to the capital investments, and a return of the balance of costs deferred at the Company's weighted average cost of capital.[16]

[15] Direct Testimony of Kim H. Smith, p. 37.
[16] Id, pp. 37-38.

Q. What is your assessment of Duke Energy Progress' proposal to defer costs related to its Grid Improvement Plan investments?

A. The proposed deferral is unnecessary and the potential future recovery of these deferred costs would amount to single-issue ratemaking that does not address a compelling public interest or meet the generally accepted criteria for this type of regulatory treatment.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in a single cost or revenue item considered in isolation. It ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

Setting rates based on a single cost or revenue item runs contrary to the basic principles of traditional utility regulation. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Alternatively, a single revenue item considered in isolation might cause a decrease in rates without recognizing counterbalancing cost increases in other areas. For these reasons, single-issue ratemaking, *absent a compelling public interest*, is generally not sound regulatory practice.

Q. Are there certain principles that should be evaluated to determine whether the adoption of single-issue cost recovery is warranted?

A. Yes, there are some generally accepted criteria that can be used to determine the appropriateness single-issue cost recovery mechanisms. Generally, an appropriate pass-through of costs, such as the one contemplated by the Company to result from the proposed deferral of Grid Improvement Plan costs, should meet *all* three of these criteria:

1) The anticipated costs or revenues are subject to significant volatility from year to year,
2) The anticipated costs or revenues are not reasonably controllable by management, and
3) The anticipated costs or revenues are substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases.

Q. Can the deferral of a cost be an example of single-issue ratemaking?

A. Technically, authorization to defer a cost does not authorize cost recovery, so an authorization for a deferral, in and of itself, would not result in single-issue ratemaking. However, to the extent that the deferred costs might be authorized for cost recovery at a later time, the future cost recovery could be an example of single-issue ratemaking, if the deferred costs do not meet the criteria I describe above.

Q. Do the Grid Improvement Plan costs that Duke Energy Progress proposes to defer meet these three criteria?

A. No, they do not. The Grid Improvement Plan costs proposed to be deferred do not appear to be volatile in nature or outside the control of the Company. Investing in and maintaining the safety, reliability, and integrity of the distribution and transmission systems are fundamental responsibilities for a utility company. In carrying out this responsibility, utilities are entitled to an opportunity to recover their prudently incurred costs. Rather than relying on deferred accounting treatment, any incremental costs associated with the Grid Improvement Plan should be considered in the context of a general rate case.

Q. Would the potential future recovery of these deferred costs also recognize counterbalancing savings in other areas?

A. No, it would not. If the proposed costs to be deferred were authorized for recovery in a future rate case, the Company would be allowed to recover the depreciation and return on these Grid Improvement Plan investments with almost no regulatory lag. However, at the same time, it would continue to earn the approved return on rate base assets in this case based on the approved rate base amount, without considering the effects of depreciation on that same rate base that would occur prior to the next rate case.

Q. What do you recommend with respect to the proposed deferral of Grid Improvement Plan costs?

A. I recommend that the Commission reject Duke Energy Progress' proposal for deferred accounting for Grid Improvement Plan investments. These grid investment costs do not warrant deferred accounting treatment and are best considered within the context of a general rate case.

<u>Multi-site Aggregate Commercial Rate</u>

Q. Please explain multi-site rate aggregation.

A. A multi-site commercial rate aggregation program would allow eligible customers with multiple service locations to aggregate their demands for purposes of power and transmission billing. For a multi-site aggregation program, the billing demand is measured as the highest hourly demand occurring simultaneously across each of a customer's participating locations, thereby measuring billing demand for the totality of the customer's participating sites as if it were a single load for billing purposes. This is described as conjunctive demand billing and should only apply to a customer's generation and transmission service. The distribution portion of the bill should be calculated using demand billing determinants established separately at each location.

Q. Why should the Company study a multi-site commercial rate aggregation program?

A. This type of aggregation properly allows a multi-site customer to capture the diversity within its loads for billing purposes, specifically in the determination of billing demand. By treating the multiple loads of a single customer as a single entity for the purpose of measuring the amount of power and transmission service provided to the customer, the customer's load is treated in a manner that is comparable to the treatment of a single-site customer with the same aggregate load shape. It is also comparable to the way the customer's load would be viewed in a competitive market.

Q. Why is it appropriate to apply a conjunctive demand rate to fixed generation and transmission costs as distinct from distribution costs?

A. Each facility owned by a multi-site customer causes unique distribution costs and therefore it is appropriate to recover those costs based on the peak demand of each individual facility. But that is not the case for fixed production and transmission costs. At the power supply and transmission level, it makes no difference whether 5 MW in a given hour is going to a single-site customer with a 5 MW load or to a multi-site customer with five facilities taking 1 MW each. The cost to produce and transmit the 5 MW in that hour is not materially different.

For a multi-site customer, it would not be unusual for each of its sites to be peaking at a different hour in each month. Under the Company's current rate structures, this means that the customer's cumulative billing demand for fixed production costs would exceed the customer's actual aggregated peak demand measured on an hour-by-hour basis (as if it were a single-site customer). In other words, under the current rate structure, the multi-site customer might be billed, say, for 5.5 MW of fixed production demand based on the sum of the individual peaks of each of its sites (occurring at different hours), whereas in fact, the customer's actual aggregate demand for fixed production demand in any hour might be no greater than 5 MW. A conjunctive demand rate can correct for this upward bias in the billing demand that would otherwise be charged to a multi-site customer by aggregating the customer's billing demands for peak demand measurement purposes. With the proper metering in place, this correction simply charges multi-site customers for the fixed production service that they actually use and places them on an equal footing with single-site customers. Under a well-designed conjunctive demand rate, a multi-site customer that has the same aggregate demand for power supply as a single-site customer pays exactly the same rate and dollar amount for power supply as that single-site customer.

Q. With a multi-site customer rate, would a commercial customer be allowed to aggregate smaller loads onto a different rate schedule designed for larger loads?

A. No, I am not proposing an aggregation program that would allow smaller aggregated loads to qualify for a different rate schedule, but rather simply to better measure the aggregated customer's demand for generation and transmission billing purposes. For example, a customer with fifteen separate sites, each with a maximum billing demand of 100 kW each that is currently being billed on the MGS rate would not be eligible to be billed at the Large General Service rates designed for customers with loads over 1,000 kW. However, its demand billing for generation and transmission costs would be aggregated for billing purposes at the MGS rates.

Q. Are you aware of any well-designed multi-site customer rates?

A. Yes. Consumers Energy in Michigan has such a rate, called the Aggregate Peak Demand Service Provision.[17] This program is available to any customer with 7 accounts or more who desires to aggregate its On-Peak Billing Demands

[17] See Sheet D-33.00 at https://www.michigan.gov/documents/mpsc/consumers13cur_579011_7.pdf

for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW. The aggregated accounts are billed under the same rate schedule and service provisions that apply to the individual sites, with the aggregate maximum capacity to all customers limited to 200,000 kW.

Puget Sound Energy also has a proposed pilot program pending before the Washington Utilities and Transportation Commission that would allow eligible customers with multiple service locations to aggregate their demands for purposes of power and transmission billing.[18]

Q. What is your recommendation regarding a multi-site commercial aggregation rate?

A. I recommend that the Commission order the Company to study and propose a conjunctive billing demand pilot program in its next general rate case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[18] Docket No. UE-190529 before the Washington Utilities and Transportation Commission, Direct Testimony of Jon A. Piliaris.

COMMISSIONER CLODFELTER: The Department of Defense, Ms. Medlyn, are you with us? Are you with us, Ms. Medlyn?

(No response.)

COMMISSIONER CLODFELTER: All right. I may come back to her, again, at the conclusion of the Public Staff case, if that's okay, Ms. Downey.

We'll come back to Mr. Quinn. One more try, Mr. Quinn.

(No response.)

COMMISSIONER CLODFELTER: All right. We will come back to Mr. Quinn and to Ms. Medlyn. I know they were appearing in the case and we had them earlier.

(Whereupon, the prefiled direct testimony of Paul J. Alvarez was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

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EXHIBITS

Alvarez Exhibit 1: Curriculum Vitae of Paul Alvarez

Alvarez Exhibit 2: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 5-3, Docket No. E-7, Sub 1214, January 27, 2020.

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.

Alvarez Exhibit 5: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-26, Docket E-7, Sub 1214, February 10, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et al*., Data Request 5-17, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 6: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-25, Docket E-7, Sub 1214, February 11, 2020 & Duke Energy Progress Response to North Carolina Justice Center, *et al*., Data Request 5-16, Docket No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 7: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 2-5, Docket No. E-7, Sub 1214, January 9, 2020.

Alvarez Exhibit 8: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 5-4, Docket No. E-7, Sub 1214, January 27, 2020.

Alvarez Exhibit 9: Duke Energy Carolinas Response to North Carolina Sustainable Energy Association, *et al.,* Data Request 2-52 and 2-53, Docket No. E-7, Sub 1214, November 25, 2019.

Alvarez Exhibit 10: Paul Alvarez Analyses of Program-Specific Cost-Benefits.

Alvarez Exhibit 11: Duke Energy Progress Response to North Carolina Justice Center, *et al*., Data Request 6-3, Docket No. E-2, Sub 1219, March 3, 2020.

Alvarez Exhibit 12: Duke Energy Progress Response to North Carolina Justice Center *et al.*, Data Request 6-8; Docket E-2, Sub 1219, March 3, 2020.

Alvarez Exhibit 13: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-28, Docket No. E-7, Sub 1214, February 10, 2020.

Alvarez Exhibit 14: Duke Energy Carolinas Response to North Carolina Justice Center, *et al*., Data Request 8-1, Docket No. E-7, Sub 1214, February 10, 2020.

Alvarez Exhibit 15: Duke Energy Progress Response to North Carolina Justice Center, *et al.*, Data Request 6-9, Docket E-2, Sub 1219, March 3, 2020.

Alvarez Exhibit 16: Duke Energy Carolinas Responses to North Carolina Sustainable Energy Association, *et al.*, Data Request 3-31 and North Carolina Justice Center, et al.,Data Request 5-32.

Alvarez Exhibit 17: Duke Energy Progress Response to North Carolina Justice Center, et al., Data Request 5-18, Docket. No. E-2, Sub 1219, February 10, 2020.

Alvarez Exhibit 18: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 5-10, Docket No. E-7, Sub 1214 and Duke Energy Progress Response to North Carolina Justice Center et al., Data Request 2-7; Docket E-2, Sub 1219.

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]

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[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:

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[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

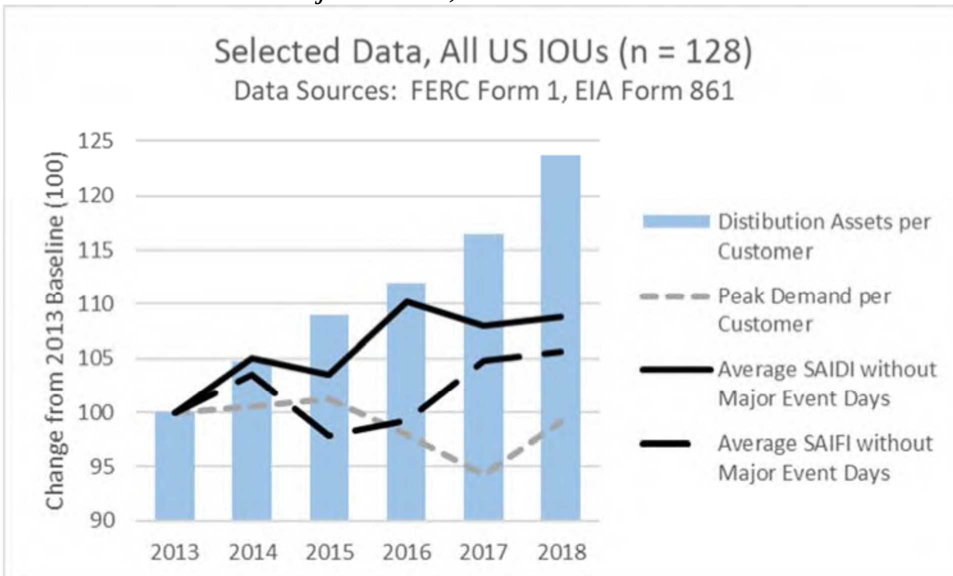

Figure 1 illustrates a counterintuitive caution to regulators: increased distribution investment is not correlated with reliability improvements. This conclusion is consistent with a Department of Energy study on U.S. electric reliability covering years 2002 to 2012.[14] Figure 1 analyzes "clear day" 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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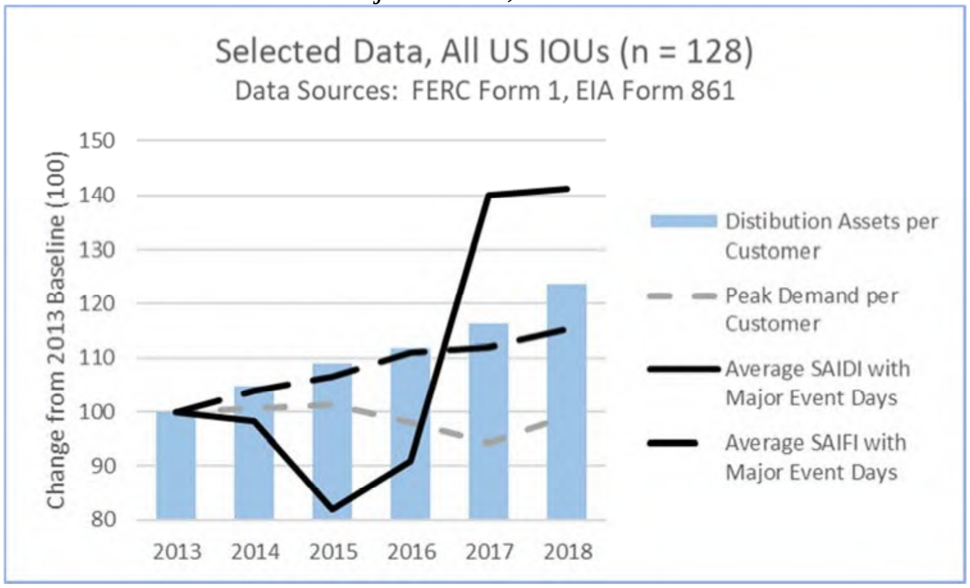
[14] Larsen P, LaCommare K, Eto J, and Sweeny J. *Assessing Changes in the Reliability of the U.S. Electric Power System.* Lawrence Berkeley National Laboratory study for the U.S. Department of Energy. August, 2015. P. 37.

[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?

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[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

[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?

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[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?

[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?

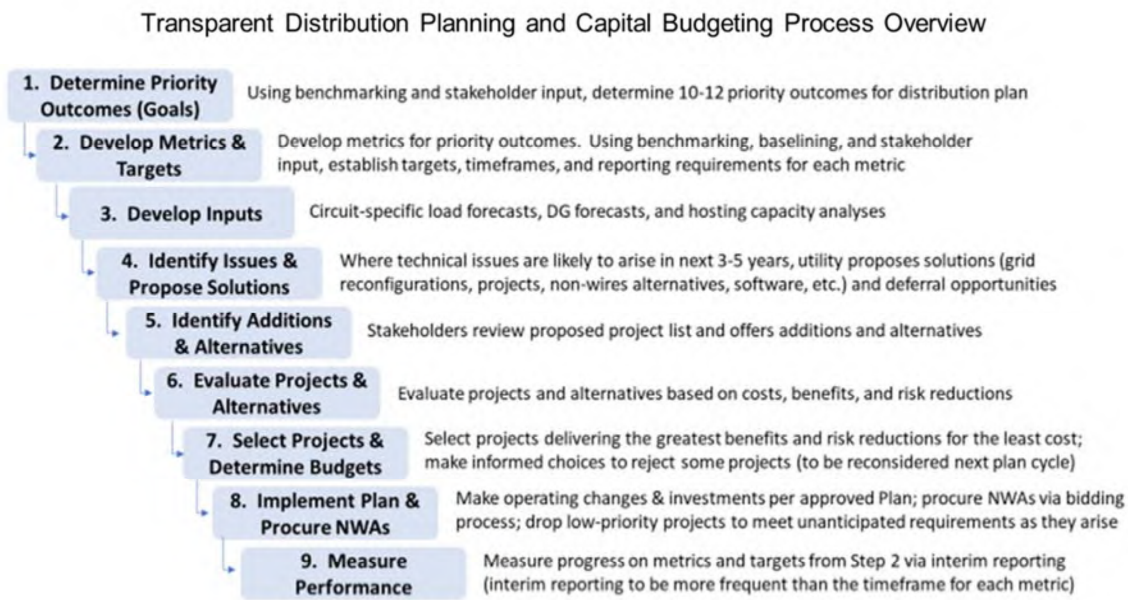
[81] Oliver Direct, Exh. 11, page 5.

[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.

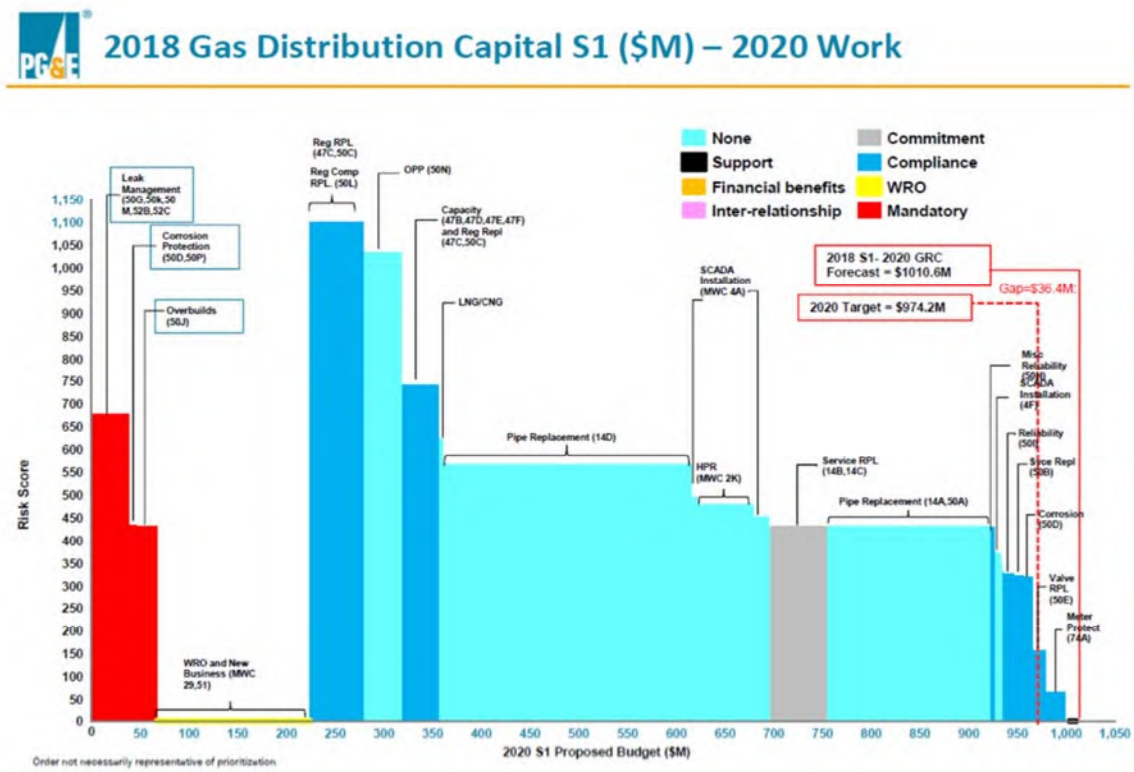
Q. STEP SEVEN APPEARS TO ALLOW STAKEHOLDERS AUTHORITY OVER DISTRIBUTION CAPITAL BUDGETS.

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?

[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

[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.

COMMISSIONER CLODFELTER: Ms. Downey, we'll go through your case now. And if it's okay with you, if they reappear, we may take them in between two of your witnesses. We may just take them in between two of the witnesses if that's okay with you.

MS. DOWNEY: That's not a problem, Commissioner Clodfelter.

(Confidential Public Staff Hinton Exhibits 1 through 3 and 6; and Public Staff Hinton Exhibits 4 and 5 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct testimony with Appendix A of John R. Hinton was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		TESTIMONY OF
Application of Duke Energy Progress,	)	JOHN R. HINTON
for Adjustment of Rates and Charges	)	PUBLIC STAFF – NORTH
Applicable to Electric Utility Service in	)	CAROLINA UTILITIES
North Carolina	)	COMMISSION

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

Testimony of John R. Hinton
On Behalf of the Public Staff
North Carolina Utilities Commission
April 13, 2020

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is John R. Hinton. I am Director of the Economic Research Division of the Public Staff of the North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603.

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

A. The purpose of my testimony is to address concerns raised by Company witnesses Stephen De May and Karl W. Newlin with regard to the credit metrics and the risk of a downgrade of Duke Energy Progress, LLC's (Company's or DEP's) debt rating. Second, I address the Company's proposed decommissioning expense. Third, I address the Company's reliance on its 2019 Integrated Resource Plan (IRP) to justify the Company's proposed accelerated depreciation of the Roxboro and Mayo coal generation units.

CREDIT METRICS

Q. HAS THE COMPANY PROVIDED THE PUBLIC STAFF WITH THE PROJECTED CREDIT METRICS UNDER A SCENARIO WHERE UNPROTECTED EXCESS DEFERRED INCOME TAX (EDIT) IS REFUNDED OVER 20 YEARS, AS PROPOSED BY DEP?

A. Yes. The Company provided confidential credit metrics of Cash Funds from Operations over total debt (FFO/Debt)[1] ratios for the period 2017 through 2023 where the EDIT is assumed to be returned over a 20-year period as originally proposed by the Company. The FFO/Debt credit metrics are attached as Confidential Exhibit 1 and it has a three-year moving average of the FFO/Debt metric as employed by Moody's with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. HAS THE COMPANY ALSO PROVIDED CREDIT METRICS OVER AN ALTERNATIVE FIVE-YEAR PERIOD?

A. Yes, at the Public Staff's request, the Company provided a FFO/Debt analysis assuming the EDIT is refunded over a five-year period as shown in Exhibit 2. As expected, the shorter time allowed to return the unprotected EDIT to customers results in lower credit metrics for the forecast period of 2020-2023. The FFO/Debt credit metrics are

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[1] The actual credit metric by Moody's is referred to as Cash Flow from Operations excluding changes in working capital over total debt.

attached as Confidential Exhibit 2 and it has a three-year moving average of the FFO/Debt metric as employed by Moody's with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. DID THE COMPANY PROVIDE SUPPORT FOR THE PROJECTED CASH FLOWS AND DEBT DATA INCORPORATED IN THE CREDIT METRICS?

A. Yes. The Public Staff was provided with several assumptions that are somewhat general in nature; such as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. WHAT DO YOU CONCLUDE FROM THE PROJECTED FFO/DEBT RATIOS THAT REFLECT A FIVE-YEAR FLOWBACK OF EDIT AS RECOMMENDED BY PUBLIC STAFF WITNESS BOSWELL?

A. As expected, the 20-year flowback of unprotected EDIT results in a higher average projected FFO to debt ratio of approximately 40 basis points. As noted in Moody's March 28, 2019 Credit Opinion, a FFO to Debt ratio that is between 21% and 23% qualifies for an "A" rating, as shown in Exhibit 3. Given that the predicted FFO/Debt metric with a five-year flowback of EDIT is below 21% in only one year, 2020, and the other metrics are 22% and 24% through 2023, I believe that unexpected financial developments, such as, significant reductions in the Company's cash flows or significant increases in its debt balances, would have to occur to reduce DEP's cash flow from operations or cause the Company to issue additional debt to trigger a downgrade.

Q. WHAT WEIGHT DOES MOODY'S PLACE ON CREDIT METRICS?

A. Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the utility regulation, and 10% weight on utility diversification. The 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. The regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the manner in which the utility manages the political and regulatory process. The ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescriptive and clear ratemaking methods. While awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Q. DOES DEP HAVE OTHER MEANS TO FINANCE THE EDIT OVER A FIVE-YEAR PERIOD?

A. Yes, I believe there are other sources of capital available to DEP that would not deteriorate its FFO/Debt metrics. The filed E-1, Item 38 contains the Company's financial forecast, which indicates that DEP projects being financed with 48% long-term debt and 52% common equity every year through 2023. From 2020 through 2023, Item 38 indicates that the Company plans to issue a total of $3.45 billion in long-term debt and infuse $2.83 billion to Duke Energy Corporation (parent). Thus, an option may exist for DEP to offset some of its debt issuances through a reduction in its planned contributions to its parent, which would better allow the Company to maintain its Moody's A2 issuer credit ratings, or, in the event of a downgrade, the ability to restore its current credit ratings. Company witnesses De May and Newlin stress the importance of maintaining DEP's credit quality, which Moody's Investor Services places as the second highest rated among Duke Energy Corporation and its other six electric utility subsidiaries as shown below:

Moody's Credit Ratings

	Long-Term Issuer Rating	First Mortgage Bonds
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Indiana	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Ohio	Baa1	A2
Duke Energy Kentucky	Baa1	NA
Duke Energy Corporation	Baa1	NA

In addition, Duke Energy Corporation[2] has announced that it would issue approximately 29 million shares in common stock, which will result in approximately $2.5 billion of net proceeds. This additional equity could allow DEP to decrease its projected equity infusions to the parent Company, alleviating the need to issue as much new debt and reduce the possibility of a downgrade.

Q. DO YOU HAVE AN ESTIMATE OF THE INCREASE IN DEP'S COST OF DEBT CAPITAL IF MOODY'S DOWNGRADED THE COMPANY'S BONDS BY ONE-NOTCH?

A. Yes, the Company believes that it is reasonable to expect that a one-notch downgrade by Moody's to A3 would increase the investor-

[2] Duke Energy Press Release, "Duke Energy announces closing of common equity stock offering with a forward component", November 21, 2019.

required bond yield by 10-basis points. The Company noted that this estimate was based on market conditions associated with a normal or typical period in the bond market. When considering the burden associated with the Company's cost of long-term debt, it is worth noting that Moody's A-rated long-term utility bond yields as of February 29, 2020, are 3.11% the lowest in over 30 years. In view of the Company's financial forecasts, it is my opinion that the added cost of debt capital from a downgrade to an "A3" rating will not be burdensome on the Company and its customers. Since 1975, DEP has had five upgrades and three downgrades as identified in Exhibit 4. Furthermore, it does not appear that any downgrade resulted from the 1986 change in the federal income tax rate.

Q. BASED UPON YOUR REVIEW OF THE FFO/DEBT CREDIT METRICS, DO YOU SUPPORT THE REFUND OF UNPROTECTED EDIT OVER FIVE YEARS?

A. Yes, I believe it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to the DEP's ratepayers and the Company.

Q. WILL THE SECURITIZATION OF DEP'S STORM COSTS TEND TO OFFSET THE REDUCED CREDIT METRICS ASSOCIATED WITH A FIVE-YEAR FLOWBACK OF EDIT?

A. Yes, I expect that regulatory lag would be effectively removed by the cash payment to compensate DEP for its storm costs of approximately $668,140,000.[3] Furthermore, I understand that credit rating agencies positively view securitization of utility costs with the prompt and certain recovery from the net proceeds from sale of the bonds. As identified in the Credit Opinions on Duke Energy Progress in Exhibit 3, the securitization of the Company's storm costs should ameliorate some of the downward pressure on the Company's credit metrics.

DECOMMISSIONING EXPENSE

Q. WHAT IS THE NUCLEAR DECOMMISSIONING TRUST FUND (NDTF)?

A. The Nuclear Regulatory Commission (NRC) requires the decommissioning of a nuclear unit after it ceases power operations. Federal law defines "decommissioning" as the safe removal of a facility from service and reduction of residual radioactivity to a level that permits termination of the NRC license. The NRC does not regulate the disposal or funding of the non-radiological waste. The NRC requires funding of NDTFs or other financial assurance for nuclear facilities to cover the cost of decommissioning.[4] NDTFs are funded by ratepayers and segregated into qualified and non-qualified

[3] DEP's storm costs as of January 31, 2020.
[4] https://www.nrc.gov/waste/decommissioning/faq.html.

trust funds set aside by utilities exclusively for nuclear decommissioning.

The Commission adopted Guidelines for Determination and Reporting of Nuclear Decommissioning Costs (Guidelines) in Docket No. E-100, Sub 56.[5] The Guidelines require utilities to perform and issue site-specific nuclear decommissioning cost studies at least once every five years and to follow up with a cost and funding report. The purpose of these studies is to ensure that the NDTFs are being efficiently funded at a sufficient level to decommission the nuclear units. On February 5, 2004, the Commission issued its Order Requiring Transfer of Internal Decommissioning Funds (E-100, Sub 56 Order), a pivotal order in that docket, in which the Commission ordered Carolina Power & Light Company, now DEP, and Duke Power, now Duke Energy Carolinas, LLC (DEC) to transfer its decommissioning monies from internal reserves to external trusts by December 31, 2016. Many years prior, Dominion Energy North Carolina (DENC) had fully incorporated the use of external decommissioning trust funds. The Public Staff had long advocated that these funds be protected through external funding, and DEP and DEC reached a Settlement with the Public Staff, which was filed on June 20, 2003, that allowed for a ten-year transfer from an internal reserve to external funding. DEC completed the transfer in

[5] Order Approving Guidelines issued November 3, 1998, in Docket No. E-100, Sub 56.

approximately one year, whereas, DEP followed the limits of the E-100, Sub 56 Order and transferred its funds in ten annual payments without any adjustment for any foregone interest.

Q. PLEASE DESCRIBE THE FUNDING MODEL THAT ENSURES SUFFICIENT FUNDS ARE AVAILABLE TO DECOMMISSION THE NUCLEAR UNITS.

A. The funding model is a large spreadsheet that targets a site-specific estimate of the future costs to decommission each plant site. The key inputs in the model are the current balance of the funds, the projected annual earnings rates on the funds, and the escalation rates that yield the future cost of decommissioning. Ms. Anger's testimony briefly describes the expense; however, an overview of the cost model is discussed in the direct testimony of DEP's witness Doss[6] in DEP's prior general case and a similar model is discussed in the rebuttal testimony of DEC's witness De May[7] in DEC's prior general rate case. Once the future costs are projected, DEP incorporates an investment strategy that is designed to generate sufficient earnings to satisfy future decommissioning expenditures that transpire over the approximate 30 to 40 years after shutting the plants down. If there is an expected shortfall of funds, the Company calculates an annuity payment to provide sufficient funds to cover any shortfall.

[6] Docket No. E-2, Sub 1142, T., Vol. 10, pages 77-85.
[7] Docket No. E-7, Sub 1146, T. Vol. 4, pages 78-80.

Q. WHAT LEVEL OF NUCLEAR DECOMMISSIONING EXPENSE DID THE COMPANY INCLUDE IN ITS APPLICATION?

A. DEP's witness Angers' proposes a total annual decommissioning expense of approximately $19.6 million, with $16.5 million for base rates and $3.1 million to be recovered from the Joint Agency Asset Rider. This is the same level of nuclear decommissioning expense included in the Company's 2017 general rate case in Docket No. E-2, Sub 1142 (DEP 2017 Rate Case).

Q. PLEASE DISCUSS THE BASIS FOR THE 2017 DECOMMISSIONING EXPENSE THAT THE COMPANY IS SEEKING IN THIS RATE CASE.

A. The 2017 approved decommissioning expense of $19.6 million was based on an estimated cost to decommission its four nuclear units that was filed as DEP's Nuclear Decommissioning Studies on April 13, 2015, in Docket No. E-100, Sub 56. DEP hired TLG Services, Inc. to estimate the current cost to decommission each of DEP's units in 2014 dollars. As example, shown below are the cost estimates for two units, Brunswick Units 1 and 2 as filed in Docket No. E-100, Sub 56.

Brunswick Nuclear Plant
Decommissioning Cost Analysis

Document D03-1695-003, Rev. 0
Page xviii of xix

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2014 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	27,681	22,007	49,688
Removal	151,069	91,928	242,996
Packaging	26,826	24,814	51,640
Transportation	31,628	20,317	51,945
Waste Disposal	137,389	114,599	251,988
Off-site Waste Processing	50,197	40,487	90,684
Program Management [1]	196,039	190,927	386,966
Site Security	68,473	61,890	130,363
Severance Program	10,044	10,330	20,374
Corporate A&G	34,589	32,965	67,553
Non-Labor Overhead	2,285	2,464	4,749
Spent Fuel Pools Isolation	8,290	12,434	20,724
Spent Fuel (Direct Expenditures) [2]	41,407	41,874	83,281
Insurance and Regulatory Fees	34,468	33,054	67,522
Energy	7,749	7,492	15,241
Characterization and Licensing Surveys	22,155	22,339	44,495
Property Taxes	2,004	1,826	3,830
Miscellaneous Equipment	7,797	7,686	15,483
Total [3]	860,088	739,433	1,599,521

Cost Element	Unit 1	Unit 2	Total
License Termination	668,569	588,285	1,256,854
Spent Fuel Management	109,958	107,980	217,938
Site Restoration	81,561	43,168	124,728
Total [3]	860,088	739,433	1,599,521

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pools O&M and EP fees
[3] Columns may not add due to rounding

TLG Services, Inc.

On September 11, 2015, DEP filed its Nuclear Decommissioning Cost and Funding Report. The Cost and Funding Report identifies the projected dates when the four units' nuclear licenses expire (2030 through 2046), the projected balances in the qualified and non-qualified Funds, the projected escalation rate to derive the future decommissioning costs, and the projected earnings rates on the qualified and non-qualified Trust Funds.

Q. DID THE COMPANY MAKE ADJUSTMENTS TO THE 2015 COST AND FUNDING REPORT IN CALCULATING THE $19.6 MILLION DECOMMISSIONING EXPENSE?

A. Yes. In preparation for the DEP 2017 Rate Case, the Company made several updates and adjustments to the 2015 Cost and Funding Report, such as the use of updated balances in its qualified trust fund and its non-qualified trust fund, and they changed the escalation rate and its projected rates of return on its qualified and non-qualified trust funds. Just an average reduction in its projected after-tax rate of returns for its qualified trust fund of less than 50 basis points raised the decommissioning expense by approximately $ 6.3 million. This large response in the decommissioning expense from a relatively small change in the projected rates of return for its qualified trust funds is largely due to the numerous years of earnings available to the fund balance before the plants are shut down and during the approximate 25 years of decommissioning,

Q. DOES THE PUBLIC STAFF HAVE CONCERNS WITH THE USE OF A 2015 COST ANALYSES AS THE BASIS FOR DEP'S REQUEST IN THIS CURRENT CASE?

A. Yes. The Public Staff has concerns with the current use of a cost estimate filed in 2015, based on dollars from 2014, which is approximately six years ago.

DEP's Decommissioning Cost Analyses for Brunswick Nuclear Plant, Shearon Harris Nuclear Plant, and H.B. Robinson Nuclear Plant (2020 Cost Analyses) filed March 12, 2020 in Docket No. E-100, Sub 56, estimated the cost to decommission DEP's four units sums to $4.2 billion in 2019 dollars, which is approximately 18% higher than estimated in the filed 2015 Cost Analyses. As such, I recommend basing any decommissioning expense in this rate case on the 2020 Cost Analyses. The updated cost analysis for the Brunswick units in 2019 dollars is shown below:

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2019 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	31,421	25,330	56,751
Removal	172,406	117,968	290,374
Packaging	32,547	27,957	60,504
Transportation	38,535	23,789	62,324
Waste Disposal	185,120	130,633	315,753
Off-site Waste Processing	49,563	43,602	93,164
Program Management [1]	239,984	219,703	459,687
Site Security	107,498	119,291	226,790
Severance Program	20,136	20,136	40,271
Corporate A&G	24,072	21,401	45,473
Non-Labor Overhead	2,689	3,154	5,844
Spent Fuel Pool Isolation	9,449	14,174	23,624
Spent Fuel (Direct Expenditures) [2]	81,731	79,815	161,545
ISFSI Construction	18,102	18,102	36,205
Insurance and Regulatory Fees	25,289	12,075	37,364
Energy	3,876	4,223	8,099
Characterization and Licensing Surveys	21,359	24,811	46,170
Property Taxes	2,891	2,601	5,492
Miscellaneous Equipment	7,494	7,662	15,156
Miscellaneous Site Services	3,402	3,062	6,464
Total [3]	1,077,566	919,488	1,997,054

Cost Element	Unit 1	Unit 2	Total
License Termination	804,493	696,692	1,501,185
Spent Fuel Management	191,586	179,415	371,002
Site Restoration	81,486	43,381	124,867
Total [3]	1,077,566	919,488	1,997,054

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pools O&M and EP fees
[3] Columns may not add due to rounding

Q. HAS DEP UPDATED ITS COST AND FUNDING REPORT TO INCORPORATE ITS 2020 COST ANALYSES?

A. No. However, the Company is required to file an updated Cost and Funding report within 120 days following the filing of its 2020 Cost Analyses for its four nuclear units. The Company will have independent advisors provide the funds' expected returns and perform various simulations to arrive at a suitable probability of success. The Company maintains that this analysis is needed to update its calculation of its decommissioning expense.

Q. WHAT ASSUMPTIONS IN DEP'S PROPOSED DECOMMISSIONING EXPENSE DOES THE PUBLIC STAFF FIND TO BE REASONABLE?

A. I believe that the projected escalation rate used in DEP's 2017 expense calculation is still reasonable. My position is based on recent projected inflation and escalation rates applied in DEP's, DEC's, and DENC's 2018 Biennial Avoided Cost proceedings and their 2019 IRPs. Other assumptions, such as the portfolio turnover rate, also appear to be reasonable. DEP incorporates a conservative approach that is reasonable by de-risking the expected rate of return or reducing the returns on the funds as the Company approach the date when the decommissioning expenditures will be needed. Furthermore, the asset allocations and the expected rates of return on the fixed income investments and other investments that comprise the Company's qualified trust funds appear reasonable and are similar to other Cost and Funding studies.

Q. WHAT ASSUMPTIONS OF DEP'S PROPOSED DECOMMISSIONING EXPENSE DOES THE PUBLIC STAFF FIND TO BE UNREASONABLE?

A. Based upon my work with the cost of common equity for regulated public utilities, my review of Public Staff witness Woolridge's testimony in this rate case, my review of the performance of DEP's qualified funds, DEP's pension funds, and other pension funds, and my review of DENC's filed 2015 Decommissioning Cost and Funding Report, I believe DEP's proposed rates of return for its qualified trust fund are unreasonable and overly conservative. The projected rates of return for the four nuclear units within DEP's qualified trust fund are shown in my Exhibit 5.

First, I believe that the 4.56% average projected long-run rate of return for DEP's qualified trust funds (as depicted in my Exhibit 5) is largely a product of an overly conservative projected rate of return on its equity investments. This is evident in the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** projected rate of return for the equity market with the qualified trust funds.

Rather, I believe a 9.00% to 9.50% expected return on the market is a more reasonable expected rate of return for these assets within the

Funds. This long-run expected market return is based on my understanding of witness Woolridge's testimony on the CAPM in this proceeding. In that, I believe a 9.50% expected rate of return on the market is reasonable. This finding is based on the expected long-run market risk premium of 5.75% combined with the risk-free rate of 3.75%[8] along with a market beta of 1.0 produces a 9.50% rate. If the Company had projected a 9.50% rate of return on its equity investments, then the Company's qualified trust fund would be expected to generate an overall expected return after taxes and fees of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This overall rate for the qualified trust fund assumes the same asset allocations and expected rates of return on its other investments with the four nuclear units.

Second, I believe that the projected long-run rate of return of approximately 4.56% is overly conservative based upon a review of past performance of the annual rates of return for this fund, after taxes and fees. My Exhibit 6 indicates at least three separate recessionary periods with negative rate of return for the qualified trust fund, which were followed by various periods of positive growth in the fund value. Based on the average annual earned rates of return calculated over long periods of time, I believe a conservative rate of return assumption for DEP's qualified trust fund would be a **[BEGIN**

[8] Docket No. E-2, Sub 1219, J. Randall Woolridge prefilled testimony, Table 6, page 84.

CONFIDENTIAL [redacted] **[END CONFIDENTIAL]** annual rate, shown below and in my Exhibit 6:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Third, while the Company's funds for its pension plan and decommissioning are not the same, there are some similarities. The two funds have similar asset allocations and the annual earned rates of return are similar in that they have an 88% correlation factor over the period 1991 through 2016. However, a significant difference in the two funding models is that the Pension Plan model assumes a significantly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** overall rate of return of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on its overall fund investments, which includes an expected rate of return of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its equity investments. If the decommissioning cost model had used the Pension Plan's expected rate of return on its equity investments, then the Company's qualified trust fund would be expected to generate an overall expected return after taxes and fees of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This overall rate of return for the fund assumes the same asset allocations and expected rates of return on its other investments with the four nuclear units. The Company notes that one of the reasons for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** expected rate of return in the qualified trust fund is its use of a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** mean return as compared to the use of an **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** return. The choice of an arithmetic mean or a geometric mean rate of return is often a matter of debate amongst cost of capital witnesses where the arithmetic mean return generally yields a higher rate. While not having a direct bearing on the appropriate rate of return for DEP's qualified trust fund, Wolfe Research[9] noted in a recent report that Duke Energy Corporation is one of two utility companies whose pension plan is fully funded at 107%.

Finally, I have reviewed other sources; such as, DENC's expected long-run rate of return on its funds as filed in their 2015 Decommissioning Cost and Funding Report.[10], and the expected long-term rate of return assumption as noted in Deloitte's 2019 Study

[9] Wolfe Research, "Utilities and Power Pondering Pensions: big focus area right now", March 26, 2020.

[10] Filed in Docket No. E-100, Sub 56, on July 2, 2015.

of Economic Assumptions[11] for the accounting of pension plans. Deloitte's 2019 Study presents a distribution of companies' expected returns that average 6.54% for 2018.

Q. WHAT IS YOUR RECOMMENDED RATE OF RETURN FOR DEP'S QUALIFIED TRUST FUND?

A. Based upon my review, I believe a 6.00% expected rate of return for the Cost and Funding model is reasonable. In my opinion, the rate is still conservative relative to DEP's projected earnings growth rates for its pension funds and it is below the fund's historical average earned rates of returns over the vast majority of historical time periods that encompass ten or more years. In my opinion, the use of a 9.50% expected return for its equity investments within DEP's qualified trust funds after paying taxes and fees equates to approximately a 6.00% overall rate of return for the qualified trust fund for the four nuclear units, while leaving the expected returns for the non-U.S. equity and fixed income returns as filed.

Q. HAS THE PUBLIC STAFF PERFORMED ITS OWN SENSITIVITY ANALYSIS AND REAL WORLD SIMULATIONS?

A. No, the Public Staff is not in a position to hire consultants and advisors to perform various simulations as DEP has done in the past. Given that this is a general rate case proceeding, I think it is better

[11] https://www2.deloitte.com/content/dam/Deloitte/us/Documents/human-capital/us-2019-study-of-economic-assumptions.pdf

to revise the cost and funding model with current cost estimates, rather than to incorporate a 2014 estimated nuclear decommissioning cost.

Q. WHAT IS YOUR RECOMMENDATION FOR DEP'S DECOMMISSIONING EXPENSE?

A. Based on the results from a Company-provided scenario that include DEP's recently filed cost estimates to decommission its four nuclear plants, the December 31, 2019 qualified and non-qualified trust fund balances, current state and federal tax rates, and the use of a 6.00% rate of return for DEP's qualified trust funds, I recommend that the Commission reduce the Company's decommissioning expense to $0. I have provided my recommendation to Public Staff witness Dorgan for incorporation in his testimony and schedules.

ACCELERATED RETIREMENT OF COAL PLANTS

Q. DO YOU SUPPORT DEP'S PROPOSED ACCELERATED RETIREMENT OF ITS COAL PLANTS?

A. No. The Company's quantitative support for the retirement is based upon its 2019 Update IRP, filed in Docket No. E-100, Sub 157, on September 30, 2019. Pursuant to Commission Rule R8-60, while the Commission's standard of review for biennial IRPs is whether they are reasonable for planning purposes, the Commission accepts IRP updates if they are as complete and fulfill the requirements set out in

Commission Rule R8-60. See Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, issued April 16, 2018, in Docket No. E-100, Sub 147. Thus, DEP's Update IRP did not receive the same scrutiny of its peak load and energy sales forecasts, projected fuel cost of natural gas, coal, and nuclear generation, projected kW and kWh reductions from the Company's energy efficiency and demand side management programs, projected cost of traditional generation, renewable generation with and without storage, and wholesale capacity purchase contracts as the 2018 biennial IRP where any of these assumptions could have a material impact on the timing of the plant retirements. Public Staff witness Metz's testimony in this proceeding discusses the time required to plan and build new generation. Furthermore, the planning effort behind consideration of building new generation and retiring existing generation should start with an IRP combined with a full examination of the wholesale market through a competitive bidding process similar to the Commission's CPRE program. This careful and involved analysis should be conducted prior to asking ratepayers to pay for the accelerated depreciation of these generation units. Furthermore, witness Metz also discusses his concerns with transmission-related issues that are typically examined in a parallel proceeding to an application for a Certificate of Public Convenience and Necessity (CPCN) for new generation or in other collaboratives.

An IRP provides an opportunity for the Company, various interveners, and the public to consider all of the demand side and supply side resources to derive a least cost plan. Conversely, a general rate case proceeding is simply not the correct forum to fully evaluate the costs and benefits of this proposal, especially when the possibility exists that added transmission-related equipment would likely be needed to insure that the plant closures would not endanger any reliability concerns.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A
PAGE 1 OF 3

QUALIFICATIONS AND EXPERIENCE

JOHN R. HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP). I filed testimony on electricity weather normalization in Docket No. E-7, Subs 620, and 989; and Docket No. E-2, Sub 833. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on the level of funding for nuclear decommissioning costs in Docket No. E-7, Subs 1026 and 1146. I filed testimony on credit metrics in Docket No. E-7, Subs 1146 and 1214. I filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs or IRP updates.

APPENDIX A
PAGE 2 OF 3

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, 148, and 158. I filed a Statement of Position in the Avoided Cost arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, Docket No. E-7, Subs 790, 791, and 1134.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Subs 333, 412, and 532; P-26, Sub 93; P-12, Sub 89; G-21, Sub 293; P-31, Sub 125; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; W-778, Sub 31; and W-218, Subs 319, 497; W-354, Sub 360, and in several smaller water utility rate cases.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001, 1018, and 1031. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from

North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. I have published an article in the National Regulatory Research Institute's Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

(Public Staff Tommy and David Williamson Exhibits 1 through 5 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled joint direct testimony with Appendix A through C of Tommy C. Williamson, Jr. and David M. Williamson was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219		JOINT TESTIMONY OF DAVID WILLIAMSON AND TOMMMY WILLIAMSON, JR. PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

**JOINT TESTIMONY OF
DAVID WILLIAMSON AND TOMMY WILLIAMSON, JR.
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION**

APRIL 13, 2020

Q. MR. DAVID WILLIAMSON, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is David Williamson. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix A to my testimony.

Q. MR. TOMMY WILLIAMSON, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Tommy Williamson. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix B to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present to the Commission the Public Staff's recommendations with regard to Duke Energy Progress, LLC's (DEP or the Company): (1) Quality of Service; (2) Vegetation Management (VM) Plan; and (3) Grid Improvement Plan (GIP or the Plan).

Q. PLEASE STATE A SUMMARY OF YOUR RECOMMENDATIONS.

A. The Public Staff makes the following recommendations to the Commission:

1. That the Company's current overall Quality of Service is adequate.
2. That the Commission should require the Company to file an annual report of its VM performance similar to the DEC report in Docket E-7, Subs 1146 and 1182.
3. That the Commission should approve the Company's 4.26% increase in VM expenses associated with labor rates.
4. That the Commission should update the filing requirements of Docket No. E-100, Sub 138A to include new indices utilized by the

North Carolina electric utilities, along with the supporting data for all such indices.

5. That the Commission should find the following GIP programs to be extraordinary in type: Self-Optimizing Grid (SOG) subcomponents – Automation and Advanced Distribution Management System (ADMS); Transmission System Intelligence; Underground Automation; and Integrated System Operation Planning (ISOP).[1]

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. We have five total exhibits, described below:

- Exhibit 1: Data response by the Company on the performance of its distribution vegetation management practices.
- Exhibit 2: Data response by the Company providing a timeline of actual and forecasted Company spend for both distribution and transmission expenses.
- Exhibit 3: Company reliability data broken down by category.
- Exhibit 4: Public Staff's GIP Evaluation Matrix.
- Exhibit 5: Summary of Public Staff Electric Division's final evaluation, including the costs associated with the programs.

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[1] Appendix C contains a list of abbreviations used in this testimony.

I. QUALITY OF SERVICE

Q. WHAT FACTORS DID YOU CONSIDER IN YOUR EVALUATION OF DEC'S OVERALL QUALITY OF SERVICE?

A. We reviewed the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) reliability scores filed by DEP with the Commission in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEP customers received by the Public Staff's Consumer Services Division; and the Consumer Statements of Position filed in Docket No. E-2, Sub 1219CS. We also considered what we know from our individual interactions with DEP and its customers.

Q. WHAT HAS BEEN THE COMPANY'S SAIDI AND SAIFI PERFORMANCE SINCE 2010?

A. SAIDI and SAIFI are measured and provided to the Commission on a system level. For the period 2010 through 2019, Company reports show that the non-Major Event Days for the SAIDI index has been slowly and moderately worsening over time and that the non-Major Event Days for the SAIFI index has been stable around a 10-year average of 1.37 over time.

SAIDI scores are indicative of how long a customer is experiencing an outage, so changes to this index are indicative of how a grid is responding to interference, such as public accidents, lightning strikes, vegetation-related outages, planned outages, etc.

SAIFI scores are indicative of the number of outages experienced by the average customer, however, a customer realistically does not experience a fraction of an outage, thus DEP customers are experiencing on average 1 or 2 outages annually.

We present a more in depth analysis of the Company's reliability scores and how they are being addressed by the Company's efforts later in our testimony with regard to the GIP.

Q. WHAT TYPES OF COMPLAINTS AND INQUIRIES HAS THE PUBLIC STAFF'S CONSUMER SERVICES DIVISION RECEIVED FROM DEP'S CUSTOMERS?

A. For the period January 2018 through January 2020, the Public Staff's Consumer Services Division received approximately 5,581 contacts from DEP customers. Of those contacts, 88% dealt with financial related issues. The largest single issue, accounting for 69% of contacts, was the establishment or modification of payment arrangements. Approximately 3% of contacts dealt with service administrative issues (e.g., facilities relocation, easements, street lighting, service theft, etc.) and approximately 3.5% of contacts were related to power reliability issues. The remaining 5.5% of contacts were classified as miscellaneous "other" inquires.

Q. WHAT TYPE OF CONCERNS WERE DISCUSSED IN THE CONSUMER STATEMENTS OF POSITION FILED IN DOCKET NO. E-2, SUB 1219CS?

A. As of March 9, 2020, approximately 436 individuals had filed consumer statements in this docket. Approximately 97% of the statements did not provide a physical address, so it is unclear if they are DEC customers. However, of the 436 statements filed, approximately 96% stated their opposition to an increase in rates.

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S QUALITY OF SERVICE?

A. We conclude that the overall Quality of Service provided by DEP to its North Carolina retail customers is adequate at this time.

II. VEGETATION MANAGEMENT

Q. HAVE THERE BEEN ANY CHANGES TO THE VEGETATION MANAGEMENT COMPLIANCE FILING SINCE THE LAST RATE CASE?

A. No, there have not been any changes to the Vegetation Management (VM) Compliance filing[2] since the Company's March 22, 2016 filing. All changes to the VM Compliance filing are required to be filed with the Commission in Docket No. E-2, Sub 1010.

[2] The Company's VM Compliance filing covers the Company's standard practice with regard to policies of trimming of its electrical system and its customer engagement policies.

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DISTRIBUTION VEGETATION MANAGEMENT PLAN?

A. The Company, in its last general rate case, updated its current VM work cycle to reflect that Urban category miles are to be trimmed on a three-year cycle and Rural category miles are to be trimmed on a seven-year cycle.

Q. PLEASE DISCUSS THE COMPANY'S ANNUAL TARGET FOR VM MILEAGE?

A. The Company's target mileage is derived by dividing the total category miles by the category trim cycle, as illustrated in Table 1, below. These target miles are the "ideal" mileage used when determining how many miles the Company should plan to trim on an annual basis.

Table 1: VM Category Target Miles

Category	Catagory Miles	Cycle Years	Annual Target Miles
Urban	1,092	3	364
Rural	32,807	7	4,687
Total	33,899		5,051

Q. PLEASE DESCRIBE THE COMPANY'S PERFORMANCE IN EXECUTING ITS DISTRIBUTION VM PLAN SINCE 2014.

A. During the discovery process in this case, the Company provided the Public Staff with the budgeted and actual performance of its VM Plan for calendar years 2014 through 2019. This data is attached as T&D Williamson Exhibit 1. This Exhibit provides an assessment of the Company's activities with regard to trimming miles and costs, herbicide application and costs, and inspections.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S EXECUTION OF THEIR VM PLAN SINCE 2014?

A. The Company has divided its distribution service territory into urban and rural areas.

For the Rural category, the Company identified 32,807 total rural miles for trimming on a seven-year cycle. This was changed from a six-year cycle to a seven-year cycle during the Company's last general rate case in 2018. For the period 2014 through 2019, the Company performed maintenance on 31,345 of 31,242 targeted rural miles, which is 103 miles ahead of the period's target mile goal.

For the Urban category, since the Company's merger with DEC, the Company has applied DEC's experience in executing the Urban category work through increased customer engagement and collaboration with municipalities on trimming clearances. The Company is able to be more aggressive in trimming vegetation from its right-of-ways – it is able to trim vegetation farther back from the power lines. This has allowed flexibility for the Company to manage the timing of maintenance in Urban areas, while maintaining adequate clearances. More aggressive trimming increases the time needed between trimming on those circuits. The Company identifies 1,095 urban miles to be managed on a three-year cycle.

Q. HOW HAS THE COMPANY PLANNED AND PERFORMED THEIR VM SINCE THE 2017 RATE CASE (SUB 1142)?

A. The Company has identified the period of 2018-2019 as transition years for the Company as they moved to a seven-year cycle for the Rural category. The Company stated that because of the shift of trimming personnel to accommodate the new budgeting of mileage for both Urban and Rural categories and the storm activity in 2018, this caused them to trim fewer miles than were targeted.

For the period 2020-2024 the Company has stated that they will be trimming in excess of their Rural target miles in order to keep the plan current.[3] The Table 2 below illustrates the annual planned miles for 2020-2024.

Table 2: VM Planned Miles 2020-2024

Category	Target Miles	Planned Miles
Rural	4,687	4,873
Urban	364	364
Total	5,051	5,237

Q. DOES THE COMPANY HAVE ANY DISTRIBUTION VM BACKLOG?

A. Yes. In response to a Public Staff discovery request, the Company states that as of January 1, 2020 it has a total of 61 backlog miles, consisting of 12 Urban miles and 49 Rural miles.[4] However, we would like to point out

[3] Urban mileage will stay the same because of the Company's increased ability to trim more aggressively through local Ordinances.

[4] Public Staff Data Request 121-4.

that this backlog of miles was generated from the transition period of moving the Rural category from a six-year cycle to a seven-year cycle. Since this transition period, the Company has been proactive in its efforts to get the plan back on track, so that it will complete its total miles on the established cycle periods.

The Company has stated that the increased efforts to trim above the annual “target” cycle amount is not reflected in the adjustment requested in this general rate case.

The Public Staff agrees with the Company’s approach in re-aligning the annual trimming mileage, so that the total mileage for each category is trimmed on its established cycle.

Q. DO YOU HAVE A RECOMMENDATION FOR THE REPORTING OF THE COMPANYS VM PERFORMANCE?

A. Yes. We recommend the Commission require the Company to file an annual VM performance report similar to that filed by DEC in Docket No. E-7, Subs 1146 and 1182.

Q. HAS THE COMPANY PROPOSED AN INCREASE TO VEGETATION MANAGEMENT PROGRAM COSTS IN THIS APPLICATION?

A. Yes. The Company proposes to increase its VM plan costs to reflect a weighted average increase of 4.26% associated with contractor VM production labor costs.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ASSESSMENT OF THE PROPOSED INCREASES IN THE VM PRODUCTION LABOR COSTS.

A. The Public Staff reviewed the labor costs contained in the contracts of the various VM companies hired by the Company to perform VM management. The Public Staff believes that the 4.26% increase requested by the Company due to an increase in contractor production labor cost rates is reasonable.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS DORGAN'S ADJUSTMENT TO THE COMPANY'S VEGETATION MANAGEMENT PROGRAM BUDGET?

A. Yes. We agree with his adjustment as shown in Dorgan Exhibit 1, Schedule 3-1(e). The Public Staff's adjustment corrects the dollar amount per mile trimmed, and allows the 4.26% increase in contractor VM production labor costs.

III. GRID IMPROVEMENT PLAN (GIP)

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR GIP TESTIMONY.

A. Our testimony is organized as follows:

A. Public Staff's approach to evaluating the deferral request;

B. Evolution of the Grid Improvement Plan;

C. Overview and Comparison of Power Forward and the Company's GIP Proposal;

D. Discussion of the current state of DEP's North Carolina electrical grid;

E. Drivers behind the Company's proposal;

F. Cost Benefit Analysis of the Company's plan;

G. The Public Staff's Evaluation Guidelines;

H. Individual program evaluation; and

I. Final program considerations.

A. Public Staff's approach to evaluating the deferral request

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S APPROACH IN EVALUATING THE COMPANY'S REQUEST FOR SPECIAL RATEMAKING TREATMENT OF ITS GRID IMPROVEMENT PLAN COSTS IN THE FORM OF AN ACCOUNTING DEFERRAL IN THIS CASE.

A. The Public Staff assessed the deferral request in two steps. First, the Electric Division reviewed the proposal to assess which, if any, programs in the request should be considered extraordinary in type and outside the scope of DEP's normal course of business. Second, the Accounting Division assessed the costs associated with any identified extraordinary type activities to determine whether or not such costs are of a magnitude that justifies deferral.

Q. HAS THE PUBLIC STAFF REVIEWED THE COMPANY'S PROPOSAL FOR A DEFERRAL OF ITS GIP COSTS?

A. Yes. We will discuss the review process and results of our technical assessment. Our testimony also incorporates the detailed assessment of the Company's cost-benefit analyses presented by Public Staff witness Thomas. In addition, Public Staff accounting witness Maness discusses whether special ratemaking treatment is appropriate.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S REVIEW PROCESS FOR EVALUATING THE GIP.

A. The Public Staff participated in Company workshops and webinars related to grid improvement planning in North Carolina. Additionally, the Public Staff submitted numerous discovery requests to the Company in order to gain a better understanding of the proposed Plan and participated in in-person meetings with the Company's technical personnel.

The Public Staff also relied on the following in our evaluation of the Company's proposal:

- The Commission's decision in Docket No. E-7, Sub 1146 (Sub 1146 Proceeding);
- Previous Smart Grid filings made by the Company in its Integrated Resource Planning (IRP) Docket, Docket No. E-100, Sub 157;
- Analysis of the current state of the Company's grid;

- Current drivers behind the need for grid investments;
- The proposed pace of GIP work proposed by the Company;
- The Company's reliability indices;
- Evaluation of the Company's Cost-Benefit Analyses;
- Perceived customer expectations; and
- Other utility grid investment/modernization proposals and investigations from around the country.

B. Evolution of the Grid Improvement Plan

Q. PLEASE PROVIDE AN OVERVIEW OF THE BACKGROUND OF THE GIP IN NORTH CAROLINA.

A. As a precursor plan to the GIP, the Company first introduced its Power/Forward Carolinas (Power Forward) proposal in 2017, in its most recent prior general rate case, Docket No. E-2, Sub 1142 (Sub 1142 Proceeding); however, the Company did not ask for any form of special rate recovery of its Power Forward plan. Duke Energy Carolinas did request special ratemaking treatment in Docket No. E-7, Sub 1146. Subsequently, the Company presented similar proposals for transmission and distribution related improvements in other dockets, including the 2018 Smart Grid Technology Plans in the IRP Docket.

Additionally, the Company held a series of grid improvement workshops following the Sub 1142 Proceeding (in conjunction with Duke Energy Carolinas, LLC (DEC)) to engage and collaborate with stakeholders. We provide a short history of the Power Forward proposal, and the evolution of the GIP to date, below.

Q. PLEASE SUMMARIZE POWER FORWARD AND THE KEY COMPONENTS OF THE PROPOSAL.

A. In the Sub 1146 Proceeding, DEC proposed various transmission and distribution related programs it designated as Power Forward. DEC stated that collectively DEC and DEP (the Companies) planned to spend an estimated $13 billion over a 10-year period on Power Forward programs across their North Carolina territories.[5]

As presented by DEC in the Sub 1146 Proceeding,[6] transmission system upgrades would be focused on: (1) replacing equipment before it failed; (2) installing equipment and processes that would notify DEC of issues that could lead to failure or outage; (3) decreasing the Companies' environmental footprint; (4) increasing physical and cyber security defenses; and (5) adding new system intelligence capabilities.

Distribution system upgrades would be focused on: (1) targeting problematic circuits for undergrounding; (2) installing or replacing equipment to harden and improve resiliency and provide back feed capabilities; (3) adding systems to self-optimize circuits in order to identify

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[5] Docket No. E-7, Sub 1146, Power Forward Carolinas Executive Technical Overview at 2, November 2017.

[6] Docket No. E-7 Sub 1146, Direct Testimony of DEC witness Simpson, at 25-32.

and resolve issues automatically; (4) improving the communications assets of key facilities; and (5) installing smart metering technologies.

Q. WHAT WAS THE PUBLIC STAFF'S POSITION REGARDING POWER FORWARD AND ITS ASSOCIATED PROGRAMS?

A. The Public Staff was not opposed to any particular Power Forward program as presented by DEC in the Sub 1146 Proceeding. In general, the Public Staff recognized that DEC has a continuing obligation to make reasonable and prudent investments in the grid as a part of ensuring reliable service to its customers. However, the Public Staff had significant concerns regarding the substantial uncertainty with the details of the Power Forward initiative, as DEC's descriptions of the programs were broad and open-ended. The Public Staff argued, and the Commission agreed, that additional information was needed to allow the Commission and Public Staff to better understand the Power Forward initiative and to assess its benefits.[7]

Based on the information available in the Sub 1146 Proceeding, the Public Staff was not persuaded that the components of the Power Forward initiative would result in modernizing the grid, but rather involved customary,

[7] Sub 1146 Final Order, at 149:
The Commission finds and concludes that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power Forward. Although the Commission concluded in this proceeding that Power Forward costs do not warrant special ratemaking treatment, the Commission finds and concludes that additional information would be helpful to the Commission, the Public Staff, and to other intervening and interested parties to better understand Power Forward projects, grid modernization in general, and the cost-effectiveness of such programs.

routine spend not outside of the scope of normal business to meet its responsibility to provide adequate and reliable service to its customers. As DEC witness Simpson stated, much of the Power Forward initiative was projected to improve DEC's outage frequency and duration, which should be part of DEC's everyday planning and operations. [8]

Q. WHAT INDIVIDUAL PROGRAMS WERE INCLUDED IN POWER FORWARD?

A. Power Forward was comprised of seven programs:

1. Targeted Undergrounding (TUG);
2. Distribution Hardening & Resiliency;
3. Transmission Improvements;
4. Self-Optimizing Grid (SOG);
5. Advanced Metering Infrastructure (AMI);
6. Communications Network Upgrades; and
7. Advanced Enterprise Systems.

Q. WHAT CIRCUMSTANCES DID DEC IDENTIFY AS DRIVING THE NEED FOR POWER FORWARD?

A. DEC cited four areas of concern: (1) increased customer expectations for more options, greater reliability, and perfect power; (2) increasing severe weather events; (3) increasing threats to physical and cyber security; and

[8] Docket No. E-7, Sub 1146, Direct Testimony of DEC witness Simpson, at 12.

(4) technology availability that enables a transition from a mechanical grid that is aging to a more modern, digitized grid.[9]

In response to these drivers, in its Sub 1146 Final Order, the Commission stated:

> …the Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service.[10]

Q. IN THE COMPANIES' MOST RECENT PRIOR RATE CASE PROCEEDINGS, WAS THERE A REQUEST FOR SPECIAL RATEMAKING TREATMENT OF POWER FORWARD COSTS?

A. DEC requested approval of a Grid Resiliency and Reliability Rider (GRR) or, in the alternative, a deferral. DEP did not request approval of a GRR Rider or deferral.

Q. DID THE COMMISSION GRANT DEC'S REQUEST FOR SPECIAL RATEMAKING TREATMENT IN THE PRIOR RATE CASE?

A. No. The Commission did not grant approval of either the GRR or the deferral request.[11] In general, the Commission found that Power Forward Carolinas

[9] Docket No. E-7, Sub 1146, Power/Forward Carolinas Executive Technical Overview, at 2.

[10] Sub 1146 Final Order, at 146.

[11] *Id.* at 146-48

programs did not represent new work or grid modernization and were part [DEC's] normal or routine operations.[12]

Specifically, with regard to the request for deferral accounting, the Commission concluded that:

> …DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral and the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary.[13]

Q. DID THE COMMISSION PROVIDE GUIDANCE IN THE SUB 1146 FINAL ORDER FOR A FUTURE DEFERRAL REQUEST?

A. Yes. The Commission found that for a deferral to be granted, "the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral."[14]

Q. BASED ON THE COMMISSION'S FINDING IN THE SUB 1146 PROCEEDING, HOW DID YOUR INVESTIGATION EVALUATE DEP'S REQUEST FOR A DEFERRAL IN THIS CASE?

A. This testimony reflects our technical investigation and evaluation of the Company's various GIP programs and our recommendation regarding whether each program meets the "extraordinary type of expenditure"

[12] *Id.*
[13] *Id.* at 148.
[14] *Id.*

requirement set forth by the Commission in its Sub 1146 Final Order. The "extraordinary magnitude" requirement is discussed further by Public Staff witness Maness.

Q. SINCE THE COMMISSION'S FINAL ORDERS IN DOCKET NO. E-2, SUB 1142 AND DOCKET NO. E-7, SUB 1146, HAVE THE COMPANIES CONTINUED PLANS FOR GRID IMPROVEMENT ACTIVITIES?

A. Yes. On October 1, 2018, the Companies filed their 2018 Smart Grid Technology Plans (Smart Grid Plans) in the IRP Docket.[15] The Smart Grid Plans are a collection of activities that both DEC and DEP are evaluating, designing, or implementing as they project how the Companies are making smart grid investments in the near term and leverage emerging technologies for the future. Some of the activities included in the Smart Grid Plans include the following:

- Physical and Cyber Security;
- Self-Optimizing Grid (SOG), including Advanced Distribution Management System (ADMS);
- Distribution System Modernization, Automation and Intelligence;
- Transmission System Modernization, Automation and Intelligence;
- Upgrades to Communication Networks;
- Energy Storage;

[15] As of November 13, 2019, the requirement for the Companies to file smart grid plans has been eliminated from Commission Rule R8-60.1.

- Advanced Metering Infrastructure; and
- Customer Programs.[16]

Based on their filings and the comments provided by other parties in the docket, the Commission accepted the Companies' positions in its Order, stating:

> The Company has determined those smart-thinking, self-optimizing grid technologies, as well as certain transmission improvements, physical and cyber security upgrades, and the advanced monitoring and communication capabilities required to enable a smart grid, meet the criteria for the SGTP [Smart Grid Technology Plan] and will be outlined within the Plans each year as applicable.[17]

Q. IS THE COMPANY'S SMART GRID PLAN COMPARABLE TO THE PROPOSED GRID IMPROVEMENT PLAN?

A. Yes, the two filings share many of the same programs and concepts. The Smart Grid Plans can be characterized as a precursor to the Company's GIP.

Q. IN ADDITION TO ITS SMART GRID PLAN, HAS THE COMPANY PROCEEDED WITH ANY OTHER GRID IMPROVEMENT ACTIVITIES?

A. Yes. Following the Sub 1142 and Sub 1146 Proceedings, the Companies held three technical workshops and a series of webinars beginning in May

[16] Customer Programs included Outage notifications, a Smart Meter Usage App, and Prepaid Advantage.

[17] Docket No. E-100, Sub 157, *Order Accepting Smart Grid Technology Plans and Requiring Additional Information*, at 22 (July 22, 2019).

of 2018 through June of 2019. The Companies' hosted events are summarized in detail as part of DEP witness Oliver Exhibits 11 through 18. These webinars and workshops were informational sessions that the Public Staff, and many of the other stakeholders, used to inform our understanding of the Company's proposed programs and the need for those programs. Members of the Public Staff that attended, including the two of us, neither supported nor opposed any of the items presented by the Company; however, we did ask questions to gain a better understanding of the Company's approach to each program.

Q. THE COMPANY STATES ON PAGE 47 OF WITNESS OLIVER'S TESTIMONY THAT THE COMPANY ATTEMPTED TO HELP THE STAKEHOLDERS "GAIN A BETTER CONSENSUS AND UNDERSTANDING OF OUR PROPOSED THREE-YEAR PLAN." WAS A CONSENSUS REACHED ON THE COMPANY'S PLAN?

A. No. It did not appear to us, during any part of the Company's webinars or workshops, that there was global consensus on any items presented by the Company.

C. Overview and Comparison of Power Forward and the Company's GIP Proposal

Q. HOW DOES THE COMPANY'S SPEND ON GIP COMPARE WITH ITS PREVIOUS POWER FORWARD PROPOSAL?

A. The Power Forward initiative proposed to spend $13 billion total between DEC and DEP over a ten-year period in the Companies' North Carolina service territories (approximately $5.5 billion in DEP and approximately $7.5 billion in DEC). In contrast, DEC and DEP propose to spend a combined $2.3 billion over a three-year period on the GIP in their North Carolina territories (approximately $0.99 billion in DEP and approximately $1.33 billion in DEC).

Q. ARE THERE PROGRAMS THAT WERE INCLUDED IN POWER FORWARD THAT ARE ALSO INCLUDED IN GIP?

A. Yes. Six of the original seven Power Forward programs included in the Sub 1146 Proceeding are included in the Company's GIP proposal in this case. Only the AMI program was not included in GIP. As noted by Public Staff witness Jack Floyd, the Company is currently working to complete its deployment of AMI meters and is including those costs in this case to be recovered through its base rates.

Q. HOW DO THE PROGRAMS THAT WERE CARRIED OVER FROM POWER FORWARD TO GIP COMPARE?

A. The table below[18] compares the total program and annual average program spending of these programs in North Carolina for both Power Forward and GIP.

Table 3: Power Forward Carolinas and GIP Comparison of Spending

CURRENT

Grid Improvement Plan Carolinas (NC)

dollars in (000's)

	NC 2020-2022
Compliance: Cost Effectiveness Justified	**$134**
Physical Security	$111
Cyber Security	$23
Cost Benefit & Cost Effectiveness Justified	**$1,649**
SOG	$722
Incremental Distribution H&R	$145
IVVC	$217
Incremental Transmission H&R	$134
TUG	$115
Energy Storage	$129
Transmission Bank Replacement	$116
OIL Breaker Replacements	$200
Rapid Technology Advancement: Cost-Effectivenes	**$536**
T&D Communications	$212
Distribution System Automation	$194
Transmission System Intelligence	$86
T&D Enterprise Systems	$28
ISOP	$7
DER Dispatch Tool	$7
Electric Vehicle Charging	$63
Power Electronics for volt/var control	$2
Total	**$2.3 billion**

PREVIOUS

Power/Forward (NC)

dollars in (000's)

	NC 2018-2027	
Compliance: Cost Effectiveness Justified		
Physical Security	$0	*new program*
Cyber Security	$0	*new program*
Cost Benefit & Cost Effectiveness Justified	**$11,804**	
SOG	$1,267	
Incremental Distribution H&R	$3,379	↓ 96%
IVVC DEC	$0	*new program*
Transmission	$2,195	
TUG	$4,962	↓ 98%
Energy Storage	$0	*new program*
Transmission Bank Replacement		
OIL Breaker Replacements		
Rapid Technology Advancement: Cost-Effectivene	**$926**	
T&D Communications	$447	
Distribution System Automation	$140	
Transmission System Intelligence		
T&D Enterprise Systems	$339	
ISOP	$0	*new program*
DER Dispatch Tool	$0	*new program*
Electric Vehicle Charging	$0	*new program*
Power Electronics for volt/var control	$0	*new program*
Total NC	**$13 billion**	

D. Discussion of the current state of North Carolina's electrical grid

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE CURRENT STATE OF DEP'S ELECTRICAL GRID IN NORTH CAROLINA.

A. As stated in the Quality of Service section of our testimony, DEP's current service is adequate at this time. We analyzed the state of the Company's

[18] E-7, Sub 1214 DEC response to NCSEA Data Request 3.

electrical grid by comparing the Company's spending on its distribution and transmission grid over time, with the overall grid reliability trends to determine a baseline for assessing the GIP proposal going forward.

Q. HOW IS THE TOTAL SPENDING ON DISTRIBUTION AND TRANSMISISON CHANGING OVER TIME?

A. As shown in T&D Williamson Exhibit 2, spending for both distribution and transmission has increased since 2010 and is projected to continue to increase over the next four years.

Q. HAS THE COMPANY MADE ANY INVESTMENTS IN PROGRAMS THAT IT INCLUDES IN THE GIP PRIOR TO THE BEGINNING OF THE DEFERRAL REQUESTED IN THIS PROCEEDING?

A. Yes. The Company has made investments in several, but not all, of the programs that are listed as part of GIP. Of the 19 programs that the Company has proposed for the Plan, work is currently ongoing for 13 of them.

Q. WHAT HAS THE COMPANY SPENT TO DATE ON GRID IMPROVEMENT PLAN RELATED COSTS?

A. The Company has spent approximately $242 million on 13 GIP-related programs since the last rate case. The table below shows the total dollars spent for each of the 13 programs.

Table4: GIP System Spend since the last rate case

Program	System Total 2017 (Sept - Dec)	System Total 2018	System Total 2019	System Total YTD Feb 2020
Self Optimizing Grid	$ 244,260	$ 11,106,276	$ 20,005,525	$ 9,653,262
Advanced DMS	-	$ 1,147,165	$ 44,078,115	$ 597,545
Transformer Retrofit	$ 2,350,082	$ 4,959,388	$ 18,116,748	$ 4,565,279
Long Duration Interruptions/HIS	-	$ 1,000,231	$ 14,376,371	$ 1,134,061
Targeted Undergrounding	$ 35,387	$ 304,791	$ 9,863,509	$ 1,688,958
Transmission H&R	-	$ 1,694,400	$ 93,684	$ 10,345,777
Oil Breaker Replacement	-	$ -	$ 7,282,594	$ 151,636
Enterprise Applications	$ 2,036	$ 70,633	$ 12,194,369	$ 699,990
Enterprise Communications	$ 175,156	$ 9,609,241	$ 11,913,651	$ 4,683,917
Power Electronics for Volt/Var	-	$ -	$ -	$ 266,919
Transmission System Intelligence	$ 780,181	$ 5,565,261	$ 1,118,377	$ 1,022,404
Distribution Automation	-	$ 2,109,284	$ 4,349,333	$ 698,033
Physical and Cyber Security	-	$ 898,032	$ 20,404,749	$ 1,450,245
Total	**$ 3,587,102**	**$ 38,464,701**	**$ 163,797,026**	**$ 36,958,027**

Q. ARE THESE INVESTMENTS NEW TO THE COMPANY?

A. No. As mentioned earlier in our testimony, the Company has been planning for these GIP-related investments since 2016 as part of its Power Forward proposal, as well as part of its 2018 Smart Grid Technology Plans.

Q. ARE ANY OF THE COSTS FOR GIP PROGRAMS THAT WERE INCURRED INCLUDED IN THE COMPANY'S BASE RATE INCREASE REQUEST IN THIS PROCEEDING?

A. Yes. All used and useful investments placed into service prior to February 1, 2020 are included in the Company's rate base in this case.

Q. DO YOU TAKE ISSUE WITH ANY OF THE GIP COSTS FOR WHICH DEP HAS REQUESTED RECOVERY IN THIS CASE?

A. No. We have not found any of the GIP programs to be unreasonable or imprudent at this time. However, many of the programs are made up of discrete activities and projects and require continuous evaluation. As noted by Public Staff witness Thomas, and discussed in more detail later in our testimony, the cost benefit analyses that DEP has relied upon for many of the programs contain weaknesses and significant uncertainties and should be subject to future review. In addition, witness Thomas noted that there are several GIP projects closed to plant that appear to have costs in excess of the original cost estimates, or lacked complete cost estimates in the CBA. As a result, the Public Staff reserves the right to challenge the prudence of any future investments in any GIP programs for which the Company requests rate recovery. Witness Thomas also recommends rigorous reporting of GIP costs and benefits, which will allow for the Commission and other parties to accurately track cost overruns and benefit shortfalls.

Q. TABLE 4 ABOVE SHOWS THAT THE COMPANY HAS BEEN PERFORMING GRID IMPROVEMENT TYPE ACTIVITIES FOR A NUMBER OF YEARS. ARE THRE ANY PROGRAMS IN THE PLAN THAT PREDATE POWER FORWARD OR GIP?

A. Yes. The Company's Distribution System Demand Response (DSDR) program dates back to 2008. While this program is not included in the Plan, the Company is utilizing the already existing infrastructure of DSDR to provide the functionality of Conservation Voltage Reduction (CVR) to the Company's grid.[19] This capability is being implemented in the DEC Plan as part of the Integrated Volt/Var Control (IVVC) program. Due to this pre-existing DSDR infrastructure in DEP, the DEP Plan is estimated to cost approximately $300 million less than the DEC Plan.

Q. PLEASE DESCRIBE THE ORIGIN OF THE COMPANY'S DSDR PROGRAM.

A. In 2007, North Carolina's Senate Bill 3 (SB3) was signed into law. In part, SB3 laid the foundation for approval and cost recovery of utility Demand Side Management (DSM) and Energy Efficiency (EE) programs in NC. DSDR was proposed by DEP in 2008 as a DSM program and ultimately approved by this Commission as an EE program in 2010 in Docket No. E-

[19] A key point to note is that it is because of this pre-existing infrastructure that DEC and the Company's plans differ by approximately $300 million.

2, Sub 926. DSDR was considered completely built-out and fully deployed as of June 2014.

Q. PLEASE DESCRIBE THE OPERATIONAL IMPACT OF THE DSDR PROGRAM.

A. When DSDR was originally proposed by the Company is 2008 it was a new type of operational mode that the Company had not previously been able to utilize. The deployment of DSDR resulted in significant circuit conditioning including: the installation of substation and distribution voltage regulating devices and capacitors; telecommunications and IT infrastructure; and some balancing of load on distribution circuits. This work allows DEP to achieve peak shaving voltage reduction of approximately 3% throughout the DEP distribution system during its hours of operation.

The current operational planning of DSDR is for approximately 80 hours a year, targeting when the grid is experiencing peak load conditions, so that it can maximize its peak shaving abilities.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR DSDR GOING FORWARD?

A. The Company is proposing to update the control settings of the existing IVVC infrastructure, which currently operates in a limited duration, peak-shaving DSDR mode, to continuously operate in CVR mode. While this work is being labeled as a "conversion," it is more accurate to describe CVR and DSDR as different operating modes.

The Company has informed the Public Staff through discovery that its position is to:

> [M]aximize the value of the assets that have been deployed where only minor investment is needed to achieve greater customer and operational benefits. To this extent, the Company recommends operating CVR mode a majority of the time with the flexibility of operating in peak shaving or emergency mode, based on conditions.[20]

Thus, it is the Public Staff understanding that the Company should maintain the original function and operation of DSDR, even after the "CVR conversion" is complete.

Q. IS NEW EQUIPMENT REQUIRED FOR THE COMPANY TO CONVERT TO CVR MODE?

A. Through discovery, the Company has stated that no new equipment is necessary for the Company to place the grid in CVR mode. To operate in CVR mode, the Company will update its current DSDR software so that the equipment at the substations will be able to operate in CVR mode.

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[20] DEP response to Public Staff Data Request 132-9.

Q. YOU MENTIONED EARLIER THAT DEP HAS PRE-EXISTING INFRASTRUCTURE THAT IT WILL UTILIZE. CAN YOU EXPLAIN WHY DEP'S BASELINE LEVEL OF INFRASTRUCTURE FOR CVR IS DIFFERENT THAN THAT OF DEC?

A. Yes. While DEP already has significant baseline infrastructure in place as a result of its pre-existing DSDR Program, witness Oliver states that DEC will need to perform work on approximately 190 substations and 985 distribution circuits to enable its proposed IVVC program in DEC's NC service territory.

E. Drivers behind the Company's proposal

Q. WHAT DOES THE COMPANY SAY ARE THE DRIVERS BEHIND THE GIP AND ITS DEFERRAL REQUEST?

A. The Company asserts that the "megatrends" require efforts to deal with the changing needs of the electrical grid for its customers, and adapting its grid to provide customers with safe and reliable power.

Likewise, the Company asserts that reliability issues and customer expectations require it to take certain actions to maintain a level of confidence by its customers in their power provider. However, the Company also acknowledges that it must recognize that "a certain level of outages and interruptions is acceptable to avoid making the system too costly."[21]

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[21] Oliver Exhibit 1, at 4.

The Company's pace of GIP implementation is what is driving the need for deferral in this proposal. The pace the Company has set is a function of its assessment of the looming impacts of megatrends and worsening reliability.

Q. THE COMPANY ASSERTS THAT THERE ARE MEGATRENDS TAKING PLACE ACROSS THE COUNTRY, AND THAT THESE SAME MEGATRENDS ARE HAPPENING HERE IN THE CAROLINAS. PLEASE DISCUSS THE COMPANY'S RECOGNITION OF THESE MEGATRENDS.

A. The Company has been discussing the topic of "megatrends" for several years, beginning during the stakeholder process following the Sub 1146 Final Order, and now included in its GIP as the primary justification for the Company's proposed programs. These megatrends, as identified by the Company, are as follows:

I. Threats to Grid Infrastructure;
II. Technology Advancements – Renewables and DER;
III. Environmental Trends;
IV. Impacts of Weather Events;
V. Grid Improvements;
VI. Concentrated Population Growth; and
VII. Customer Expectations.

Q. DOES THE PUBLIC STAFF GENERALLY AGREE WITH THE MEGATRENDS IDENTIFIED BY DEP?

A. Yes. However, the Public Staff would not characterize a number of these trends as new, novel, or outside the scope of normal business.

The Public Staff agrees that DEP should continue to address these trends by making the necessary grid infrastructure investments to ensure safety and reliability, ensure proper security measures are in place to protect those investments, address customer migration trends, ensure the investments take advantage of the latest technological advancement to provide the increased levels of customer service required, and cost effectively protect against weather events.

Q. PLEASE DESCRIBE THE COMPANY'S USE OF RELIABILITY INDICES TO JUSTIFY THE INVESTMENTS IT HAS IDENTIFIED IN ITS GIP.

A. In addition to the two reliability indices that electric utilities have traditionally used to evaluate its reliability performance, SAIDI and SAIFI, the Company has begun to utilize the Customers Experiencing Multiple Interruptions (CEMI-6) index over the last few years.

Q. PLEASE DESCRIBE THE THREE RELIABILITY INDICES.

A. SAIDI: System Average Interruption Duration Index – This scoring metric represents the average duration of sustained customer interruptions per customer occurring during the analysis period. It is the average time customers are without power for the entire system. It is determined by dividing the sum of all sustained customer interruption durations, in minutes, by the total number of customers served.

SAIFI: System Average Interruption Frequency Index – This scoring metric represents the average frequency of sustained interruptions[22] per customer for the entire system occurring during the analysis period. It is calculated by dividing the total number of sustained customer interruptions by the total number of customers served.

CEMI-6: Customers Experiencing Multiple Interruptions – This scoring metric represents the percentage of customers experiencing six or more sustained interruptions in a 12-month period. This metric is a good indicator of the worst performing circuits, which would allow for better targeting of resources to the most critical needs.

Q. DOES THE COMPANY REPORT THESE RELIABILITY INDEX SCORES TO THE COMMISSION?

A. In accordance with Commission Rule R8-40A(d),[23] the Company files twelve-month trailing reliability scores for both SAIDI and SAIFI, on a quarterly basis, in Docket No. E-100, Sub 138A (Sub 138A). The Company does not report CEMI-6 scores to the Commission. The Company also does

[22] Sustained interruptions refers to those interruptions lasting longer than five minutes.

[23] Adopted by the Commission in its November 25, 2013 *Order Adopting Rule Establishing Electric Utility Service Quality Metrics and Requiring Filing of Quarterly Reports and Requesting Further Comments*.

not report the individual categories that make up the total SAIDI and SAIFI scores.

We recommend that if the Company is going to utilize additional indices to analyze its level of reliability, the Commission should require the Company to update the filing requirements of Sub 138A to include these new indices. Additionally, we recommend that the Commission require the Company to file the full breakdown of individual categories for all index calculations, so that the Public Staff and Commission are aware of the drivers of both positive and negative contributors to reliability.

Table 3 below provides the year-end twelve-month trailing SAIDI and SAIFI scores, excluding Major Event Days (MED), that have been filed with the Commission in the Sub 138A docket. The Company reports SAIDI and SAIFI scores for both MEDs and non-MEDs in these filings.

Table 5: SAIDI and SAIFI Scores as filed by the Company

	Duke Energy Progress (excluding MEDs)	
Year	**SAIFI**	**SAIDI**
2yr_Avg	1.32	157.50
3yr_Avg	1.31	152.67
5yr_Avg	1.33	150.40
10yr_Avg	1.37	137.60
Year	**SAIFI**	**SAIDI**
2019	1.29	149
2018	1.35	166
2017	1.30	143
2016	1.30	153
2015	1.41	141
2014	1.22	124
2013	1.24	106
2012	1.69	145
2011	1.53	134
2010	1.36	115

Q. PLEASE DISCUSS HOW THESE SCORES ARE CALCULATED.

A. The Company uses Customer Interruption (CI) and Customer Minutes of Interruption (CMI) data, along with customer population, to calculate the SAIDI and SAIFI reliability scores. CI and CMI data is derived from various contributing categories such as vegetation related outages, public accidents, wildlife, equipment failure, lightning, etc. T&D Williamson Exhibit 3 shows the classification of these scores by category.

Q. DEP WITNESS OLIVER PROVIDES THE COMPANY'S SAIDI AND SAIFI TRENDS THROUGH 2018. HAS THE COMPANY PROVIDED THE PUBLIC STAFF WITH SCORES FOR CALENDAR YEAR 2019?

A. Yes. As shown in T&D Williamson Exhibit 3, the Company's reliability scores for both SAIDI and SAIFI have been updated to include 2019.

Q. HAS THE COMPANY BEEN ABLE TO PROVIDE SCORES FOR THE CEMI-6 RELIABILITY INDEX FOR THE PUBLIC STAFF'S REVIEW?

A. Yes. Through the discovery process, the Company has been able to provide these scores to the Public Staff, but only for the last three years.

Q. ARE YOU CONCERNED THAT THE CEMI-6 RELIABILITY INDEX SCORES CAN ONLY BE PROVIDED FOR THIS LIMITED PERIOD OF TIME?

A. Yes. Having only three years of scores makes it difficult to establish a meaningful baseline reference. Thus, CEMI-6, as a newly utilized reliability metric, will provide only limited value in assessing the need to make changes to the status quo. Analytical trend data over a number of years is needed to provide an adequate baseline that allows the Company to better asses the reliability score that it should be targeting.

F. Cost Benefit Analysis of the Company's plan

Q. DID THE PUBLIC STAFF INVESTIGATE THE COMPANY'S COST BENEFIT ANALAYSES?

A. Yes. The Company's Cost Benefit Analyses (CBA) for its various GIP programs are discussed in detail by Public Staff witness Thomas in his testimony in this case.

Q. HOW DOES WITNESS THOMAS' ANALYSES OF THE GIP CBAs INFLUENCE YOUR EVALUATION?

A. Witness Thomas makes several recommendations regarding the quantification of the costs and benefits included in the Company's CBAs as they relate to GIP. Table 4 below summarizes the impacts to the benefit-cost ratios as a result of the recommendations witness Thomas was able to quantify for programs that the Company had calculated a CBA,[24] as well as the percent of total benefits that are customer reliability benefits. It is important to note that the impact of other recommendations may change the benefit-cost ratios of other programs not shown below.

In our evaluation, we reviewed the conclusions in witness Thomas' testimony to understand (1) whether each GIP program would be cost beneficial and (2) what proportion of the claimed benefits were attributable

[24] Witness Thomas estimated the impact of implementing the following recommendations to the IVVC (for DEC) and SOG CBAs: (1) removal of CO_2 benefits from DSDR and IVVC (for DEC); (2) inclusion of momentary outages in SOG; and (3) capping long-duration outages on the DTR program.

to customer reliability benefits. This second consideration was important because customer reliability benefits are difficult to quantify and will not lead to a reduction in customer rates that offsets the increase in rate base proposed in the GIP. We viewed programs with high levels of reliability benefits with skepticism, as we agree with DEP witness Oliver that "a certain level of outages and interruptions is acceptable to avoid making the system too costly."[25]

Table 6: Cost Benefit Analyses with Public Staff Adjustment

Description	Benefits As Filed		Benefits with PS Recommendations	
	BCR	% Customer Reliability Benefits	BCR	% Customer Reliability Benefits
SOG (DEP)	3.1	93%	**1.6**	**93%**
DTR (DEC+DEP)	1.5	96%	**1.4**	**96%**
IVVC (DEC)	1.2	0%	**0.9**	**0%**
DSDR (DEP)	35.3	0%	**27.8**	**0%**
Trans Line H&R (DEP)	3.3	100%	3.3	100%
Transformer Bank Replacements (DEP)	0.8	20%	0.8	20%
Oil Breaker Replacements (DEP)	1.6	74%	1.6	74%
TUG (DEP+DEC)	12.1	92%	12.1	92%
LDI / HIS (DEP+DEC)	29.4	100%	29.4	100%

[25] *See* Oliver Exhibit 1, at 4.

Q. BASED ON THE RESULTS OF WITNESS THOMAS' EVALUATION, ARE YOU RECOMMENDING ANY PROGRAMS NOT BE IMPLEMENTED?

A. No. At this time, we recognize that the quantification of costs and benefits from GIP programs is challenging, particularly with regard to customer reliability. While the GIP proposal includes significant costs, only about 10% of the benefits are considered operational and would be expected to lead to future rate reductions.

G. Public Staff's GIP Evaluation Guidelines

Q. PLEASE DESCRIBE HOW THE PUBLIC STAFF DEVELOPED ITS MATRIX FOR EVALUATING THE COMPANY'S GIP PROPOSAL.

A. Determining whether a program meets the definition of grid modernization requires an understanding of the current state of the utility's grid, the role the proposed programs play within both the existing and future grid, how they interact with legacy devices, and how the programs meet the objectives of interested stakeholders. We recognize that any evaluation of programs will necessarily have some level of subjectivity, but we attempted to assess each program with as much objectivity as reasonably possible.

To do so, we followed a two-step approach. First, we reviewed each GIP program to determine whether it exhibited characteristics of a grid modernization program. Second, we created an evaluation matrix, which we used to rank each GIP program proposal on metrics we consider important in defining grid modernization. The combined results of these two review processes were used to inform our final determination of whether each GIP program meets the "extraordinary type" test discussed earlier in our testimony. The results of this two-step approach are discussed below.

Q. PLEASE DESCRIBE THE FIRST STEP OF YOUR EVALUATION PROCESS.

A. In determining whether each program should be considered grid modernization, the Public Staff relied upon several information sources, as discussed below. Consistent with our position on the Company's previous Power Forward proposal, we sought to identify those programs that would "bring the current grid up to new standards of operation and reliability," as opposed to "investments needed to maintain or restore the grid to historic levels of operation and reliability."[26] Investments that reflect an expansion or acceleration of existing programs could be classified as grid improvement, but not necessarily grid modernization. This type of characterization would not meet our threshold for "unique and extraordinary."

We were also cognizant of the Commission's conclusions in the Sub 1146 Final Order that rejected grid modernization programs that are the "kinds of activities in which the Company engages or should engage on a routine and

[26] Docket No, E-7, Sub 1146, Direct Testimony of Public Staff witness Tommy C. Williamson, Jr, at 8.

continuous basis."[27] In its Sub 1146 Final Order, the Commission defined the requirements that it would examine before determining that a proposed investment would meet the "extraordinary expenditure" test and be authorized for deferral. The Order states that the Company would need to demonstrate that the costs "can be properly classified as Power Forward and grid modernization."[28]

Q. WHAT OTHER RESOURCES DID THE PUBLIC STAFF RELY UPON IN MAKING ITS GRID MODERNIZATION DETERMINATION?

A. We reviewed the U. S. Department of Energy's (DOE) Modern Distribution Grid Project (DOE Project), and found it to be useful in our evaluation. Also referred to as the "next generation distribution system platform" (DSPx), the DOE Project is a collaboration with state regulators, utility companies, energy services companies, and technology developers across several states (including NY, CA, HI, MN, and DC) with the goal of developing guidance to assist in the development and evaluation of distribution grid modernization.[29]

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[27] Sub 1146 Final Order, at 146.

[28] *Id.* at 148.

[29] The Modern Distribution Grid Project report can be found on the Pacific Northwest National Laboratory (PNNL) website: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

The DOE Project is intended to "develop a consistent understanding of requirements to inform investments in grid modernization," and consists of three volumes.

- Volume I - Customer and State Policy Driven Functionality defines the functional scope for a modern grid platform.
- Volume II - Advanced Technology Market Assessment presents a survey of grid modernization technologies and their functions.
- Volume III - Decision Guide provides a user guide for the application of the first two volumes.

Figure 1 below summarizes the three volumes, as well as showing at what stage of the grid modernization process they should be applied.

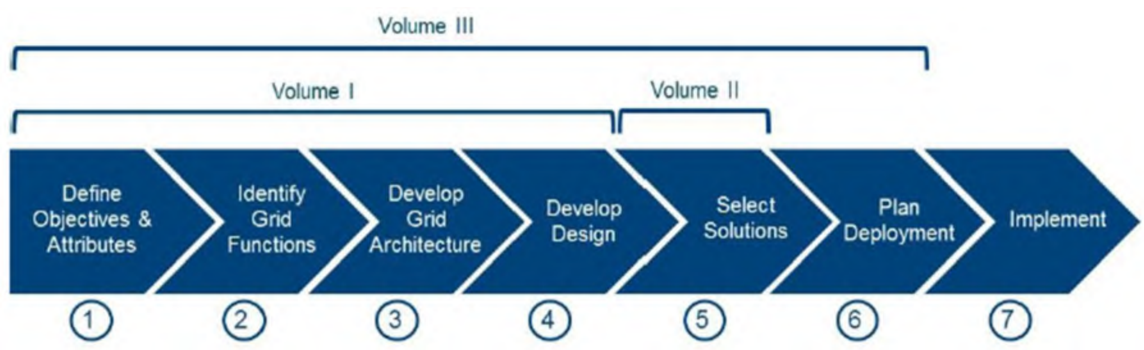

Figure 1: Modern Grid Decision Process. Source: DOE Project, Volume III, at 11.

Q. HOW DID THE DOE PROJECT ASSIST THE PUBLIC STAFF IN EVALUATING THE GIP PROPOSAL?

A. The three volumes offer a detailed look at how grid modernization programs should be orientated, how to define desired grid attributes, what functions are necessary, how grid modernization should be structured, and how the appropriate devices and technologies should be selected. The DOE Project is primarily a guidance document, and as such, we applied the findings and considerations to our state's grid needs and policy. Overall, the DOE Project helped us to put DEP's GIP proposal in context, and helped in our evaluation of whether each GIP program should be considered grid modernization under the definitions provided. We relied primarily on Volume III when reviewing GIP Programs.

Q. DID YOU RELY ON ANY OTHER EXTERNAL DATA SOURCES?

A. Yes. We looked to other states that are considered to be further along than North Carolina in their evaluation of grid modernization efforts to see if any of their work might inform our evaluation. During our investigation, we discovered a document developed by the California Public Utilities Commission (CPUC) Staff titled Staff White Paper on Grid Modernization (CPUC Framework), which was largely an adaptation of the DOE Project.[30] The CPUC Framework was created to help identify and prioritize grid modernization investments for California's electrical grid by understanding the function of each identified technology and the integration challenges they are designed to solve. The CPUC Framework provides a list of requirements for future grid modernization filings by California utilities as

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[30] *See* California Public Utilities Commission Rulemaking 14-08-013. Decision 18-03-023, issued March 22, 2018, adopted the grid modernization classification framework proposed by CPUC Staff.

well as a matrix that details how various technology categories: (1) interact with specific use cases; (2) provide certain grid functions; (3) support certain grid management activities; and (4) address certain system or integration challenges.

Q. IS THE CPUC FRAMEWORK APPLICABLE TO THE ONGOING GRID IMPROVEMENT/MODERNIZATION EFFORTS IN NORTH CAROLINA?

A. Yes. Because the principles that the CPUC used in determining its CPUC Framework are derived from the DOE Project, North Carolina could use a variation of the CPUC Framework to help guide our improvement and modernization efforts. However, as a point of clarification, the CPUC, beginning in 2015, developed rules for distribution resource planning (DRP) that are currently not required in North Carolina. The CPUC Framework was largely a means of evaluating programs to be considered in its DRP.

Q. BASED UPON THE FIRST STEP OF YOUR EVALUATION PROCESS, WERE THERE ANY PROGRAMS THAT DID NOT ADEQUATELY MEET THE DEFINITION OF GRID MODERNIZATION?

A. Yes. The following DEP GIP programs failed the first step of our evaluation: (1) Distribution H&R; (2) Transmission H&R; (3) Transformer Bank Replacements; (4) TUG; and (5) Long Duration Interruption/High Impact Sites (LDI/HIS). In addition, these programs did not meet any of the technology categories considered in the DOE Project or the CPUC Framework. This evaluation supports our determination that these programs are customary grid investments and not of an extraordinary type. It is important to note that we used the CPUC Framework as a guide, but that North Carolina and California are at different stages of grid modernization. Thus, we classify programs that met at least one grid modernization technology category definition, which we then labeled in our evaluation as "possible grid modernization."

Q. PLEASE DESCRIBE THE SECOND STEP OF YOUR EVALUATION PROCESS.

A. The second step consisted of creating and applying an evaluation matrix. We determined a set of metrics on which to evaluate each program, based upon our experience with grid modernization in North Carolina and our research into grid modernization efforts across the country.

Q. WHICH METRICS DID YOU CONSIDER IMPORTANT TO INCLUDE?

A. We considered three primary metrics in our evaluation: (1) the transformative impact of the program; (2) timing of the deployment; and (3) how the program fits in grid modernization architecture. Together, these three metrics help inform what we consider to be an "extraordinary type" activity, which would meet the first prong of the two pronged deferral test.

Q. HOW DID YOU SCORE THE GIP PROGRAMS USING THESE METRICS?

A. Each program was given a score by metric, with the available scores ranging from one (the lowest ranking score) to three (the highest ranking score). In order to bring as much objectivity to this process as possible, we assigned a description to each metric. Each program of GIP was then given a score from one to three by metric, based upon the best-fit description. Finally, a weighted score was calculated based upon the weights for each metric, as described further below. The higher the score, the more likely we viewed the program as an "extraordinary type."

Q. PLEASE DESCRIBE THE TRANSFORMATIVE METRIC.

A. The "transformative" metric is the primary driver for determining whether or not a proposed program has characteristics of grid modernization. We assigned each program or component[31] to one of the following three categories:

1. The program or component is providing no new capabilities, or current procedures and initiatives provide similar benefits;
2. The program or component is providing some limited new capabilities; or,
3. The program or component is providing significant new capabilities.

Because of the importance of classifying a project as a transformative project with regard to grid improvement or modernization, we assigned this metric a weight of 2.0 in our evaluation. The weighting of this metric is designed to reflect whether the Company is proposing programs that will bring the grid up to new standards of operation and reliability rather than

[31] Several programs are comprised of distinct individual initiatives, which are referred to as components.

providing for investments that are needed to maintain or restore the grid to historic levels of operation and reliability.

Q. PLEASE DESCRIBE THE TIMING METRIC.

A. The "timing" metric assigns each program or component to one of the following three categories:

1. The program or component is ongoing work, but the proposed 3-year timeline for implementation is not critical to grid operations;
2. The program or component is new work, but the proposed 3-year timeline for implementation is not critical to grid operations; or,
3. The program or component is urgent work and the proposed 3-year implementation is critical to grid operations.

We assigned this metric a weight of 1.0 in our evaluation.

The DOE Project provides guidance on the timing of grid modernization rollouts, which assisted us in evaluating the timing of each GIP program.[32]

Q. PLEASE DESCRIBE THE GRID ARCHITECTURE METRIC.

A. The "grid architecture" metric is based upon the concept of an overarching grid architecture, which the DOE Project considers an important guiding principle in deploying coordinated gird modernization efforts. Based upon our review of the DOE Project Volume III, we have defined three levels of "grid architecture" which we used to rank GIP programs:

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[32] *See* DOE Project Volume III at 14-18, 27-31.

1. This program is standalone and operates outside grid modernization architecture.
2. This program is an application dependent upon core components.[33]
3. This program is a core component of grid modernization (foundational).

We assigned this metric a weight of 1.0 in our evaluation. It is important to differentiate between a core component of grid modernization architecture (such as an intelligent grid sensing or switching device, which enables other grid modernization programs and would be scored 3.0) and a physical grid component which does not interact or enable other grid modernization programs (such as animal mitigation infrastructure, which would be scored 1.0). Software applications which build upon core grid components would generally be scored 2.0.

Q. PLEASE DESCRIBE HOW YOU SCORED EACH OF THESE PROJECTS FOR THE SECOND STEP OF THE EVALUATION.

A. The scores of 1.0, 2.0, and 3.0 have been previously defined for each metric, but generally, a higher score indicates a higher ranking. After we scored each program on each metric, we then calculated the weighted score by multiplying each metric's score by the weight assigned to each metric and summing the results. Because we assigned a weight of 2.0 to

[33] *Id.* at 24-26. Core Components include: Physical infrastructure (wires, transformers, switches, etc.); Advanced protection and controls; Sensing and situational awareness; Operational communications; and Planning tools and models (DER & Load forecasting, power flow analysis, etc.).

the transformative metric, projects could score a maximum score of 12 and a minimum score of 4. The spreadsheet for this calculation is provided as T&D Williamson Exhibit No. 4. The main considerations for each GIP program or component is described in more detail later in our testimony.

Q. IF THE PUBLIC STAFF'S EVALUATION ELIMINATES SPECIFIC PROGRAMS FROM "EXTRAORDINARY TYPE" CONSIDERATION, DOES THE PUBLIC STAFF ALSO BELIEVE THOSE PROGRAMS SHOULD BE COMPLETELY ELIMINATED FROM THE COMPANY'S WORK PLAN?

A. No. The Company should be undertaking all activities that are necessary and prudent to ensure safe, reliable, and economical power delivery to its customers. The Public Staff's evaluation is focused on the individual GIP programs and an assessment of their qualification as an "extraordinary type" activity for consideration for deferral accounting.

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS ABOUT WHAT ACTIVITES QUALIFY FOR SPECIAL RATEMAKING TREATMENT?

A. Yes. The Public Staff believes that under the current construct of the Company's GIP, any item that provides a benefit or "improvement" to the grid could ultimately be considered for special ratemaking treatment such as deferral, whether in this initial phase of GIP, or in potential later phases.

Based on the information provided by DEP during our investigation, we believe that each program that has been proposed by the Company will likely improve the performance of the grid; however, the same can be said about any equipment placed into service, assuming that a utility is only placing or replacing needed equipment that is used and useful. This reality creates a certain tension between "business as usual" activities and activities involving the installation of new technologies that can elevate the electrical grid to a new operational standard. In our evaluation, we have attempted to distinguish between these two characteristics that are in tension.

We believe that merely applying the term "grid improvement" is too generic and overly broad for this purpose. Our evaluation process attempts to identify programs that are extraordinary in type and will transform the Company's day-to-day grid operations and planning toward a business model of the future prior to consideration for special ratemaking deferral treatment.

H. Individual GIP Program Evaluation

Q. BASED ON THE EVALUATION METRICS YOU DISCUSSED ABOVE, PLEASE PROVIDE YOUR FINAL EVALUATION RESULTS FOR EACH GIP PROGRAM YOU DETERMINED TO QUALIFY AS AN EXTRAORDINARY TYPE.

A. We applied the information mentioned throughout our testimony to aid in our evaluation and understanding of each GIP program proposed by the Company. The table below summarizes the programs or components identified as an extraordinary type of activity. These identified programs or components are listed in T&D Williamson Exhibit 5.

Table 7: GIP Programs Classified as Extraordinary Type for DEP

Focus	Description	Program Currently Exist?	Possible Grid Mod?	PS Rubric Weighted Score	Extraordinary TYPE?	DEP20	DEP21	DEP22	DEP Total
Modernize	ISOP	NO	Yes	12	YES	$1.8	$.2	$.4	**$2.5**
Optimize	SOG Automation + Control	YES	Yes	11	YES	$36.1	$44.4	$49.1	**$129.6**
Modernize	Transmission System Intelliger	NO	Yes	11	YES	$6.8	$11.3	$5.6	**$23.7**
Optimize	SOG ADMS	NO	Yes	11	YES	$6.	$5.7	$7.4	**$19.1**
Modernize	UG System automation	YES	Yes	11	YES	$1.8	$4.3	$5.1	**$11.2**

Q. PLEASE DESCRIBE ANY THEMES SHARED IN COMMON BY THESE PROGRAMS.

A. In reviewing our evaluation results, we observed the following with regard to the programs classified as extraordinary type:

- In the transformative metric, all five programs were considered to provide significant new capabilities to the grid;
- In the grid architecture metric, all five programs were considered a core component of grid modernization;

- In the timing metric, four of the five programs were determined to be programs that could begin implementation, but that the 3-year timeframe proposed by the Company was not critical to grid operations.

Q. PLEASE DESCRIBE EACH OF THESE FIVE QUALIFYING PROGRAMS.

A. <u>SOG Automation and ADMS</u> – SOG Automation projects provide intelligence and control capability for the self-optimizing grid. The grid intelligence captured by circuit protective devices will be utilized by the new Advanced Distribution Automation System (ADMS) to optimize power flow and reduce the impact of faults experienced by customers. The combination of the automation equipment and the ADMS will allow DEC's grid to operate in a new manner and at an additional level of reliability. Data collected by the Company will allow for a greater level of distribution planning. It is the new capabilities provided by the ADMS and the automated devices that led us score it 3.0 on the transformative metric. The ADMS will also allow greater functionality of the CVR operational mode, earning it a score of 3.0 on the grid architecture metric. The Company indicated that a SOG circuit will be designed to pick up 70% of the companion circuit's load during 90% of the annual hours. On the timing metric, we believe that customers on SOG circuits will see improved reliability, but that a 3-year timeline is not critical for deployment of the entire SOG proposal.

Transmission System Intelligence – The focus of this program is reduce the impacts on the transmission system through better protection and monitoring of system equipment. This program has four main components: (1) replacement of electro-mechanical relays with remotely operated digital relays; (2) deployment of intelligence and monitoring technology to provide asset health data for use in predictive maintenance programs; (3) deployment of remote monitoring and control functionality for substation and transmission line devices; and (4) resiliency projects that will leverage capabilities of this program, along with existing equipment capabilities to more rapidly respond to system outages and disturbances. These components have the potential to be utilized by other programs as DEP improves its grid management practices, and as such we scored it 3.0 in the grid architecture metric.

The combination of these four components will allow DEP to operate its grid in a way it had not previously been able to do, earning it a 3.0 score on the transformative metric. The new capabilities are summarized as follows:

- Health and Risk Monitoring (HRM) will extend asset life by identifying issues before failure.
- Digital relay design will enable quicker recovery from fault events.
- Remote control transmission switches will enable faster identification and isolation of system faults and trouble spots leading to faster service restoration.

- This technology will allow more data to be collected and analyzed to better operate the transmission system.
- The data collected through this program will help inform future planning efforts.

This program will increase the amount of data that is collected as the Company develops more detailed transmission planning. As with many of the GIP programs, we encourage the Company to invest in ways that make its system more efficient, but we believe the 3-year timeline is not critical, so we scored it 2.0 on the timing metric.

Underground System Automation – This component of the Company's Distribution Automation program seeks to upgrade the protection and control of underground distribution systems serving customers in high-density locations (urban downtown areas, business districts, airports, entertainment venues), earning it a score of 3.0 on the grid architecture metric. This component will give the Company the ability to automatically reconfigure underground systems in order to isolate faults, reduce the effect of outages similar to SOG, and operate in a new, more efficient manner, earning it a score of 3.0 on the transformative metric. Similar to the previous programs, we continue to encourage the Company to invest in ways that make its system more efficient, but we believe the 3-year timeline is not critical, so we scored it 2.0 on the timing metric.

ISOP – This program is a planning tool that takes a holistic approach to integrate planning for the Company's generation, transmission, and distribution systems. ISOP is a multi-year program that takes into account operational and economic concerns.

For example, ISOP may focus on developing a methodology to determine the combined value of DER and customer programs. This effort would consider the benefit of delaying or deferring traditional deployment of wires solutions, and how non-traditional alternatives may assist in meeting the bulk generation needs: regulating reserves, balancing reserves, and capacity reserves. Because of these methodology impacts, we scored it 3.0 on both the transformative and grid architecture metrics.

The ISOP program also scored 3.0 in the timing metric because we believe the improved modeling and analytical tools and processes expected to be developed through ISOP will be a critical to grid modernization in the Carolinas. Key elements of ISOP provide significant capabilities that can aid in the grid modernization process. The Company describes these elements as improved forecasting, advanced distribution planning, non-traditional grid solutions, and integrated planning from generation to distribution that feeds into the IRP.[34] These modeling tools and themes are recurrent in the DOE Project literature.

[34] See Joint Report of DEC, DEP and Public Staff on ISOP Workshop in Docket No. E-100, Sub 157 (January 21, 2020).

Q. FOR THE GIP PROGRAMS THAT YOU DETERMINED DID NOT QUALIFY AS AN EXTRAORDINARY TYPE OF ACTIVITY, PLEASE DESCRIBE ANY COMMON THEMES SHARED BY THESE PROGRAMS.

A. In reviewing our evaluation results, we observed the following common themes among the 33 programs or components that did not qualify as extraordinary in type:

- For the transformative metric, none of these 33 programs or components, for which deferral is requested, were considered as adding significant new capabilities to the grid.[35]
- For the timing metric, for 32 of the 33 programs or components, it was determined that the three-year time period was not critical to grid operations. Only Next Generation Cellular, a component of the Enterprise Communications program, has a three-year time period deemed critical due to the end of 2G/3G vendor support in 2022.
- Thirteen of the programs or components not recommended did not meet any of the grid modernization technology categorizations found in the CPUC Framework.

[35] The Energy Storage program was considered to contribute significant new capabilities; however, it is not included in this deferral request by the Company. The Electric Transportation program was also not included in this deferral request by the Company.

Q. PLEASE PROVIDE YOUR ANALYSIS OF EACH PROGRAM NOT CATEGORIZED AS AN "EXTRAORDINARY TYPE."

Self-Optimizing Grid (SOG) Capacity and Connectivity – SOG capacity projects focus on increasing substation transformer and distribution line capacity. SOG connectivity projects create ties between different distribution circuits. These two SOG components represent traditional technologies and utilize material and equipment that are current industry standards and are activities that have occurred, and continue to occur, as a normal part of operations; therefore, we scored these programs 1.0 for both the transformative and timing metrics. These components will be installed to complement other components of the SOG program, which is why we scored these two components 3.0 on the grid architecture metric.

DSDR Conversion to Conservation Voltage Reduction (CVR) – As discussed earlier, DEP fully deployed DSDR in June 2014. DEP plans to "convert" DSDR to add a CVR operational mode. While DSDR is designed to produce 3.5% voltage reduction for a limited time[36] across the entire DEP system, CVR will provide an approximate 2% of continuous voltage reduction across the DEP distribution system. This will be accomplished by modification of the existing control software and applied to the existing voltage regulating equipment and capacitors. This program enables the distribution system to optimize voltage and reactive power needs by

[36] DSDR is a mode designated for emergency grid situations.

coordinating and configuring the intelligent devices on the grid using a management control system, ADMS. CVR is an additional operating mode that is dependent upon ADMS that was installed years prior as part of the DSDR initiative, and, as such, we scored it 2.0 on the grid architecture metric. The ADMS utilizes the data collected to operate the grid more efficiently while maintaining distribution voltages within acceptable operating limits. CVR allows grid operators to lower system voltage in order to reduce overall demand and energy. CVR mode is intended to operate throughout the year during approximately 90% of the hours. CVR uses pre-existing equipment to provide limited new capabilities, and, as such, was scored 2.0 in the transformative metric. We believe CVR is a modification to the operating platform, but we do not believe it is critical to deploy CVR in the 3-year timeframe as proposed by the Company, thus we scored it 1.0 on the timing metric.

<u>Distribution Hardening and Resiliency (H&R) – Flood Hardening</u> – This program seeks to mitigate the effects to at-risk equipment from flooding. Work includes: (1) creating alternate power feeds for radial distribution lines and substations that reside in or cross flood-prone areas; (2) hardening facilities at river crossings where distribution lines are vulnerable during extreme flooding events; and (3) improved guy-wire support for equipment in identified flood zones. These types of activities are not providing new or innovative capabilities to the grid, and so we scored this program 1.0 on the transformative metric. This program is a standalone program that is part of

the normal and ongoing mitigation planning process with distribution lines, and so we scored this program 1.0 on both the timing and grid architecture metrics.

Long Duration Interruption/High Impact Sites (LDI/HIS) – This program seeks to reduce the frequency and duration of outages in areas that may have a higher duration outage than average. The majority of this program will: (1) reconductor distribution lines with larger wire; (2) relocate distribution lines; and (3) install ties between distribution circuits. This type of distribution work has been historically performed by DEP. Similar to the Flood Hardening mentioned above, these types of activities are not providing new or innovative capabilities to the grid, and as such, we scored this program 1.0 on the transformative metric. This program is also a standalone program that is part of the normal and ongoing planning process with distribution lines, and as such, we scored this program 1.0 on both the timing and grid architecture metrics.

Distribution Transformer Retrofit – This program focuses on overhead transformers currently in service. The work at most of these locations involves adding fused disconnect switches, lightning arrestors, and animal protection to the existing transformer. These additions should improve the power reliability of customers by: (1) reducing the risk of outages due to animal interference and lightning, and (2) limiting the effect of faults that occur on the customer side of the transformer to that particular segment only. These types of additions are not providing new capabilities to the Company's grid, and as such, we scored this program 1.0 on the transformative metric. However, we considered this program a core component to the Company's ability to update the design of the distribution system, which is why we scored this program 3.0 on the grid architecture metric.

The equipment used for this program has been standard in the electric utility industry for decades. DEP is now deploying this program, which has been in place for DEC since 2009, which is why we scored this program 1.0 on the timing metric.

Transformer Bank Replacement – This program will work together with the Health and Risk Management (HRM) software.[37] The focus of this program is to accelerate the replacement of substation transformers prior to their failure. The combination of the two programs will formalize what had been an informal collection/review of transformer health status. The program will analyze transformer health and rank units for replacement consideration based on their measured risk of failure. Based on review of this risk ranking, an annual replacement plan will be developed by the Company. Because of this new ability to manage the health of the transformer bank, we scored this program 3.0 on the grid architecture metric.

[37] HRM was deployed for DEP transmission transformers in early 2019.

DEP has developed an initial “watch list” that contains 199 substation transformer units to be monitored under this program. The table below provides a summary of the units being monitored as part of the Company’s watch list.

Table 8: Transformer Bank Replacement Program - Watch List

Capacity (MVA)	<20	21-50	51-200	201-500	>500	Total
Quantity	84	72	14	28	1	199

DEP has historically been replacing 2-3 of these units annually. DEP is now proposing to accelerate this initiative to 5-10 units annually; however, budget limitations prohibit them from doing so at this time. Substation transformer units up to 50 MVA are widely used throughout the DEP service territory. DEP states that the normal procurement period for these units ranges from 12-24 months. In the event an emergency replacement is required, DEP has access to multiple layers of substation transformer inventory, including DEP, DEC, Duke Energy Enterprise, and the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) program.[38]

The Public Staff supports the monitoring activities of the Transformer Bank Replacement program and encourages the Company to continue this effort in order to minimize potential customer outages caused by transformer

[38] RESTORE is a national program for the sharing of substation and transmission equipment between member utilities. DEP is a RESTORE member.

failure. However, because it is a pre-existing initiative and DEP has access to multiple inventories of substation transformers in the event of an actual emergency, we scored this program 1.0 on both the transformative and timing metrics. In addition, Oliver Exhibit 1 specifically identifies "proactive replacement of pad mount transformers" and preventing load service events with "high consequences with adverse occurrences" (which a transformer bank failure would fall under) as part of its base maintenance work.

Distribution Automation – This program consists of four primary components that seek to minimize the effects of outages on the distribution system. We found one component, Underground Distribution Automation, to qualify as extraordinary type and the remaining three components are discussed below.

The Hydraulic to Electronic Recloser component will replace oil-filled reclosers with current industry standard electronic reclosers. These electronic units allow for remote operation and provide ongoing and continuous monitoring of distribution system health.

The System Intelligence and Monitoring component is a pilot seeking to replace an existing feeder management system. It seeks to build a distribution diagnostic tool to give grid operators the ability to troubleshoot developing problems as they occur.

The Fuse Replacement component involves replacing single-use fuses with an Automatic Lateral Device (ALD). Typically, these fuses are installed on a distribution line at a point that then creates a downstream distribution lateral section. Currently when a single-use fuse operates, there is the need for a technician to be dispatched to replace the fuse. The ALD has the capability of resetting itself without need of a technician site visit.

All three components scored 3.0 on the grid architecture metric because they are core components. The program, as a whole, was determined to provide limited new capabilities and as such was scored 2.0 on the transformative metric. These components were determined to be ongoing work and should continue at normal pace and, because of this, they scored 1.0 on the timing metric.

<u>Transmission Hardening and Resiliency (H&R)</u> – This program has three main components: (1) line hardening and resiliency; (2) flood hardening; and (3) animal mitigation.

DEP has identified 13 substations that qualify for flood hardening work in the form of installation of permanent flood walls or fast deployable barriers. All thirteen locations will have one of these options completed by March 15, 2020. In addition, three of these substations will either be relocated or elevated by 2025. The Company has indicated that it has modified its future substation site selection criteria to use the higher of: (1) the 100-year flood elevation plus 2 feet for a non-critical facility, or the 100-year flood elevation plus 3 feet for a critical facility; (2) the 500-year flood elevation plus 1 foot; or, (3) the Design Flood Elevation adopted by the community.

The animal mitigation component installs protective equipment in an attempt to decrease the risk and impact of outages caused by animal interference.

The Public Staff finds that the three components of this program provide no new capabilities; represent ongoing work that should be continued at a normal pace; and are standalone and not part of grid modernization architecture.

<u>Oil Breaker Replacement</u> – This program seeks to replace oil-filled circuit breakers (OCB) in the DEP transmission and distribution fleet. OCBs have been in operation throughout the electric utility industry and in DEP's service territory for over a century. OCBs use oil as the medium to extinguish electrical arcs created during the opening of the breaker contacts. Circuit breaker technology has continued to evolve in the electric utility industry leading to technologies available for the replacement of OCBs, and we find that no new capabilities are readily available from these technologies, which is why we scored these programs 1.0 on the transformative metric.

According to discovery responses provided by DEP, the Company began installing both the gas and vacuum breaker technologies by 1975. Transmission OCBs are being replaced primarily with breakers that utilize gas (sulfur-hexafluoride) and distribution OCBs are being replaced primarily with breakers that utilize vacuum technology to extinguish electrical arcs. These replacement breaker types will allow for two-way communications and remote operation capability, which provide a core component to grid modernization architecture. For this reason, we scored these components 3.0 on the grid architecture metric.

The table below shows the approximate number of circuit breakers currently in operation in the DEP transmission and distribution fleet.

Table 9: DEP Transmission and Distribution Fleet Breaker Types

Oil	Gas	Vacuum	Total
1,031	1,555	140	2,726

According to discovery responses provided by DEP, the installation of new gas and vacuum breakers (combined) exceeded new OCB installations in approximately 1988, and has been the predominant installations ever since. Since 1997, DEP has installed approximately 1,340 gas or vacuum breakers and only 25 OCB's. For these reasons, we scored these components 1.0 on the timing metric.

We believe that this is ongoing work that should be continued, and the Company should continue to monitor and evaluate existing OCB installations and make decisions to replace those units based on established testing criteria and field observations.

<u>Physical and Cyber Security</u> continues to be a major area of concern for all electric utilities in the country. This program is comprised of multiple components that seek to improve security of the transmission and distribution system. DEP is generally using North American Reliability

Corporation (NERC) Critical Infrastructure Protection (CIP) standards to guide and inform its actions in this program.

We believe that the need for physical and cyber security will be continually present and will evolve to address emerging threats. DEP has indicated that none of the planned expenditures in GIP are required for NERC CIP compliance. In addition, no component of this program is required to be completed due to any industry or regulatory mandate. For these reasons, we scored all components of this program 1.0 on the timing metric.

We also believe that for the transformative metric, while the Device Entry Alert System, Secure Access Device Management, and the Line Device Protection programs provide limited additions beyond the current capabilities that are available to the Company for physical and cyber security, programs like the Substation Physical Security and Windows Based Unit Change Outs are standard types of physical security upgrades.

For the grid architecture metric, the Device Entry Alert System and Line Device Protection programs are both core components of grid architecture, and as such, they scored 3.0 on this metric. The Secure Access Device Management program is an application that is dependent upon core grid components and was scored 2.0 on this metric. Lastly, the Substation Physical Security and the Windows Based Unit Change Outs are standalone programs and operate outside of the grid modernization architecture, which is why we scored them 1.0 on the grid architecture metric.

Targeted Undergrounding (TUG) – Based on discovery responses provided by DEP, the total number of distribution miles are shown in the table below.

Table 10: Distribution Lines in DEP (miles)

Distribution	Primary	Secondary	Total
Overhead	28,242	9,950	38,192
Underground	16,189	12,672	28,861
Total	44,431	22,622	67,053

DEP has been undergrounding distribution lines for decades, including conversions of overhead to underground, which is why we scored it 1.0 on the timing metric. The materials and technology used today for TUG are also used throughout the industry and are not new, or expanding the grid's abilities to communicate with other systems, which is why we scored it 1.0 on the transformative metric and 1.0 on the grid architecture metric.

Enterprise Communications – This program consists of nine components. Most of these components replace equipment or infrastructure that have been part of and are expected to remain part of normal operations. Only Vehicle Area Network and Network Asset Systems are new platforms the Company plans to deploy.

The Next Generation Cellular component replaces obsolete 2G/3G modems with the current 4G/5G standard modems. The Company currently has the 2G/3G[39] version of cellular communications equipment installed on some substation and line equipment. The Company has negotiated with its current cellular communications vendor to support the existing 2G/3G standard until the end of 2022. After that date, the 2G/3G modems will not communicate and this will isolate the Company's equipment.

Mission Critical Voice replaces radios used by field personnel to communicate between and within the field of operations. The current system of radios used by DEP is not compatible with other Duke Energy jurisdictions and does not allow communications between personnel from those different jurisdictions. This program will deploy a common platform of radios that is compatible throughout all Duke Energy jurisdictions.

Mission Critical Transport replaces existing fiber cable, optical and microwave systems that are at end-of-life. This component seeks to expand the capacity and reliability of the existing DEP communications network.

The components of this program offer no new capabilities and, with the exception of Next Generation Cellular, are part of normal ongoing work. Next Generation Cellular is deemed an urgent need due to its specific deadline for completion.

[39] 2G/3G refers to the standard used for cellular communicants. The 2G/3G standard is obsolete and is being replaced by the 4G/5G standard.

Enterprise Applications – This program seeks to provide enterprise-wide software for transmission, distribution, enterprise systems, and grid analytics.

The Health Risk Management (HRM) tool gathers and analyzes transmission system data for use in predictive and preventative maintenance efforts. The Enterprise Distribution System Health (EDSH) tool seeks to provide a platform to improve planning, governance, and customer delivery of power quality.

The Public Staff finds that this program, as a whole, provides some limited new capabilities and was scored 2.0 on the transformative metric. This program is dependent upon core components of grid modernization architecture and as such, was scored 2.0 on the grid architecture metric. The program will provide some limited new capabilities and represents ongoing work that should be continued at a normal pace.

DER Dispatch Enterprise Tool – As of 2018, North Carolina is the state with the second highest amount of interconnected solar DER in the United States, with over 3,000 MW of installed solar capacity. To assist in managing this level of DER, DEP (where most of the solar capacity in the State has been deployed) implemented a rudimentary dispatch tool. The current tool allows DEP to interrupt DER in 50 MW blocks in certain conditions, as needed, and requires phone calls between DEP dispatchers and DER sites to coordinate and execute the process. DEC, with far less solar capacity, did not deploy the same tool; however, with the Competitive Procurement of Renewable Energy program seeking solar capacity in DEC's territory, a single coordinated tool was designed for both jurisdictions.

The proposed DER Dispatch Tool will be deployed in both DEP and DEC, replacing the existing tool in DEP. It will allow the Company to curtail DER in blocks as small as 1 MW, and allow for more automation of the process by eliminating the need for a DEP dispatcher to place a call to DER sites for execution to be completed. However, the Company has indicated that the DER Dispatch Tool as implemented will only be used in emergency situations for curtailment of solar facilities. DEP does not currently plan to use the DER Dispatch Tool to manage energy storage or for the forecasting of solar facilities. As such, we scored it 2.0 for transformative metric, as the program only provides limited new capabilities. Due to the existing tools available to the Company, we scored it 1.0 in the timing metric. Finally, this software application is dependent on core components of grid architecture, and thus receives a 2.0 on this metric.

Power Electronics for Volt/VAR Control –This program is a pilot and is in the infancy stages of research. It seeks to assist grid operators to better manage power quality issues associated with the high level of DER expected on the DEP system.

The Public Staff finds that this program provides limited new capabilities; represents new work but that a 3-year completion is not critical to grid operations; and is a core component to other programs that are part of grid modernization architecture. We encourage the Company to continue learning how to better operate their grid through this pilot.

Q. ARE THERE PROGRAMS THAT THE COMPANY PRESENTED IN THE GIP PROPOSAL BUT DID NOT INCLUDE IN THE DEFERRAL REQUEST?

A. Yes. The Company included the Electric Transportation (ET) and Energy Storage programs in its presentations and final proposal; however, the costs for these programs are not included in the GIP deferral request.

Q. IS THE PUBLIC STAFF MAKING A RECOMMENDATION FOR THE ELECTRIC TRANSPORTATION AND ENERGY STORAGE PROGRAMS?

A. No, not at this time. The Company's ET proposal is currently being addressed in a separate proceeding, Docket No. E-2, Sub 1197. The Public Staff has filed comments and a proposed order in that docket.

As discussed in DEP's 2018 IRP, energy storage continues to evolve as a resource in the electric industry.[40] DEP states that the candidates for storage projects will be designed and assessed on a case-by-case basis.

[40] *See* Chapter 6 of DEP's 2018 IRP - INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP) AND BATTERY STORAGE.

Currently, the number and location of sites that qualify for assessment are in the planning stages and are operating as potential pilots. We believe that energy storage should be evaluated as part of the ISOP process to inform the Company as to its best uses and business cases.

While no program costs have been included for consideration in the Company's GIP proposal for ET or energy storage, we encourage the Company to continue its evaluations of these programs to identify reasonable and prudent applications. The Public Staff will evaluate any future requests involving these programs, should they arise.

I. Final program considerations for a deferral

Q. BASED ON YOUR EVALUATION, WHICH GIP PROGRAMS QUALIFY AS AN EXTRAORDINARY TYPE OF ACTIVITY FOR FURTHER CONSIDERATION FOR DEFERRAL ACCOUNTING?

A. A summary of the final evaluation and recommendation of certain programs that we provided to the Public Staff's Accounting Division is presented as T&D Williamson Exhibit 5.

Q. WITH YOUR EVALUATION OF GIP PROGRAMS COMPLETED FOR THIS CASE, WILL THE PUBLIC STAFF MAKE THE SAME DETERMINATIONS IN FUTURE CASES?

A. No. We evaluated the programs in this case based on the specifics as presented by the Company in this case. Company proposals may change over time and as such, we will continue to evaluate those proposals in each case on their own merits. In addition, the methods and inputs used to inform our evaluation in this case are based on the current information and resources available to us at the time of this filing. Our decisions may change over time as new information becomes available, and we will modify our evaluation process as necessary. As stated earlier in our testimony, our agreement with the recovery of costs for GIP programs in this proceeding should not be interpreted as implying continual approval of the costs of these same programs in the future. The Public Staff reserves the right to challenge the recovery of future costs associated with any of the GIP programs in future proceedings before the Commission.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DAVID WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. My current responsibilities within the Electric Division include reviewing applications and making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; reviewing applications and making recommendations on transmission proposals for certificates of environmental compatibility and public convenience and necessity; and interpreting and applying utility service rules and regulations. Additionally, I am currently serving as a co-chairman on the National Association of State Utility and Consumer Advocates' (NASUCA) DER and EE Committee.

I have filed testimony in various DEC, DEP, and DENC's Demand Side Management/Energy Efficiency rider proceedings, as well as recently in DENC's most recent general rate case in Docket No. E-22, Sub 562.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

TOMMY WILLIAMSON, JR.

I am an Engineer with the Public Staff's Electric Division. I graduated from North Carolina State University with a Bachelor in Science in Electrical Engineering. I have approximately 3 years of electrical distribution design and construction experience with Florida Power & Light Company. During that time I designed distribution circuits for overhead and underground services from the substation through to end users. This was inclusive of but not limited to; customer load analysis, feeder line loading analysis, facilities construction and installation. I then served 11 years as an Engineer with General Electric Company. In this role at General Electric Company, I represented the company with electrical design engineers, industrial and commercial end customers, and installation contractors to develop technical specifications for the procurement and use of electrical distribution equipment.

Since my employment with the Public Staff, I have reviewed customer quality of service complaints, transmission and distribution construction projects, vegetation management, small generator interconnection procedures, and filed testimony in general rate cases and North Carolina Interconnection Procedures.

Abbreviations List

AACE	American Association of Cost Engineering
ADMS	Advanced Distribution Management System
ALD	Automatic Lateral Device
AMI	Advanced Metering Infrastructure
BCR	Benefit Cost Ratio
C&I	Commercial and Industrial
CBA	Cost Benefit Analysis
CEMI-6	Customers Experiencing Multiple Interruptions
CI	Customer Interruptions
CIP	Critical Infrastructure Protection
CMI	Customer Minutes Interrupted
COSS	Cost of Service Study
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Data Request
DRP	Distribution Resource Planning
DSDR	Distribution System Demand Response
DSM	Demand Side Management
DSPx	Next Generation Distribution System Platform
DTR	Distribution Transformer Retrofit
EDSH	Enterprise Distribution System Health
EE	Energy Efficiency
ET	Electric Transportation
GIP	Grid Improvement Plan
GRR	Grid Reliability and Resiliency (Rider)
H&R	Hardening and Resiliency
HRM	Health and Risk Monitoring
ICE	Interruption Cost Estimator
IRP	Integrated Resource Plan
ISOP	Integrated System Operations Planning
IVVC	Integrated Volt Var Control
LBNL	Lawrence Berkeley National Laboratory
LDI / HIS	Long Duration Impact / High Impact Sites
M&S	Materials and Supplies

MED	Major Event Day
NASUCA	National Association of State Utility and Consumer Advocates
NC	North Carolina
NERC	North American Reliability Corporation
O&M	Operations and Maintenance
OCB	Oil-filled Circuit Breakers
PFC	Power Forward Carolinas
PNNL	Pacific Northwest National Laboratory
PRMR	Planning Reserve Margin Requirement
PURPA	Public Utilities Regulatory Policies Act
QF	Qualified Facility
RESTORE	Regional Equipment Sharing for Transmission Outage Restoration
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB3	Senate Bill 3 (Renewable Energy Portfolio Standard)
SCP	Summer Coincident Peak
SOG	Self-Optimizing Grid
SWPA	Summer/Winter Peak and Average
T&D	Transmission and Distribution
TMT	Targeted Management Tool
TUG	Targeted Undergrounding
UCT	Utility Cost Test
VEPCO	Virginia Electric and Power Company
VM	Vegetation Management
WTA	Willingness to Accept
WTP	Willingness to Pay

(Public Staff Thomas Exhibits 1 through 9 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct testimony with Appendix A and B of Jeff Thomas was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		TESTIMONY OF JEFF THOMAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF JEFF THOMAS
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THE COMPANY'S APPLICATION.

A. In this proceeding, I investigated Duke Energy Progress, LLC's (DEP or the Company) proposed Grid Improvement Plan (GIP),[1] and in particular the associated Cost-Benefit Analyses (CBAs) that support certain GIP programs, as provided in Oliver Exhibit 7 and then summarized in Oliver

[1] Appendix B contains a list of abbreviations used in this testimony.

Exhibit 8. Specifically, the programs which had CBAs conducted are listed below, along with brief descriptions of each program.[2]

- Self-Optimizing Grid (SOG) – segmentation of and interconnection between distribution circuits, enabling automatic isolation of faults and reducing the number of affected customers.
- Distribution System Demand Response (DSDR) Conversion[3] – DEP intends to convert its DSDR program, a peak shaving operational mode of Volt Var Optimization (VVO), into a Conservation Voltage Reduction (CVR) operational mode. This proposed conversion trades peak reduction benefits (from DSDR) for energy savings benefits (from CVR).
- Transmission Transformer Bank Replacements – accelerated proactive replacements of transformers in an effort to reduce unexpected failures and the associated outages.
- Distribution Transformer Retrofits (DTR) – accelerated proactive retrofits of distribution transformers with devices enabling segmentation, as well as additional protective features.
- Transmission Hardening and Resiliency (H&R), consisting of:

[2] For a more detailed description of each program, please refer to the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson and the direct testimony of DEC witness Jay Oliver, Exhibit 10.

[3] I refer to this concept of converting from the DSDR operational mode to the CVR operational mode as the "DSDR Program," "DSDR," "DSDR Conversion," or "DSDR to CVR Conversion" interchangeably throughout my testimony. Note that the IVVC program proposed by DEC in Docket No. E-7, Sub 1214 is VVO which would operate in CVR mode.

   - Substation flood mitigation – relocating and reinforcing substations prone to flooding during major storms.
   - Transmission Line Projects – targeted line rebuilds to withstand extreme weather as well as accelerated upgrades of the 44 kV system.
- Oil Breaker replacement (Distribution and Transmission) – accelerated replacements of oil circuit breakers with gas circuit breakers (transmission) or vacuum circuit breakers (distribution).
- Long Duration Impact / High Impact Sites (LDI / HIS) – extreme hardening, circuit relocations, new circuit ties, and undergrounding of distribution lines to improve reliability to sites with high potential for long-duration outages.
- Targeted Underground (TUG) projects – burying distribution lines in areas with a history of unusually high outages.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an analysis of GIP CBAs in support of the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson. I present to the Commission the results and recommendations of the Public Staff's investigation into the reasonableness of the GIP CBAs provided by DEP. I will summarize how the CBAs were performed, what benefit categories were included and how the benefits were estimated, and how costs were estimated. In addition, I will highlight the Public Staff's concerns with the CBAs, present some relevant sensitivity analyses performed by the Public Staff, and share our conclusions regarding the cost-effectiveness of the selected programs. While I do not recommend that any GIP programs be rejected based solely upon their CBA, I do share the Public Staff's findings and recommendations so that the Commission can view the CBA results in the appropriate light and require revisions as it deems appropriate.

The importance of accurate and realistic quantification of benefits and costs is critical when assessing large-scale grid improvement investments such as those included within the GIP. The estimated benefits from the Company's GIP proposal are massive, equal to nearly three times the total fuel and fuel-related expenses incurred across DEP's and Duke Energy Carolinas, LLC's (DEC) entire system in the twelve months ending December 2019.[4] A key point that I will elaborate on later in my testimony is that a majority (87%) of these benefits are categorized as customer reliability benefits, which are not derived from the operation of the electricity system, but rather they reflect estimates of reduced economic activity caused by interruptions. In light of the significant implications to ratepayers of the GIP proposal, it is critical that benefit estimations – and particularly customer reliability benefits – be as realistically and accurately evaluated, quantified, and allocated as possible. In addition, this is important to the

[4] *See* DEC's December Monthly Fuel Report, Docket No. E-7, Sub 1198 and DEP's December Monthly Fuel Report, Docket No. E-2, Sub 1201.

ratepayers as well as to the utility; the cost to customers from poor service quality can influence the rate of return authorized by the Commission, and may one day be used to determine a utility's rate of return, under a theoretical performance-based ratemaking structure.[5]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Overview of GIP CBAs;

II. Discussion of GIP program benefits;

III. Discussion of GIP program costs;

IV. Findings related to GIP cost recovery; and,

V. Recommendations to the Commission.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am including nine exhibits, described below:

Exhibit 1. 2015 *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, by Lawrence Berkeley National Laboratory (LBNL)

Exhibit 2. DEC response to Public Staff Data Request (DR) 133-7 in Docket No. E-7, Sub 1214.

[5] *See* National Renewable Energy Laboratory, *Next-Generation Performance-Based Regulation*, NREL Report No. NREL/TP-6A50-68512 (September 2017), at 14, *available at* https://www.nrel.gov/docs/fy17osti/68512.pdf.

Exhibit 3. DEC response to Public Staff DR 133-13 in Docket No. E-7, Sub 1214.

Exhibit 4. DEC response to Public Staff DR 179-4 in Docket No. E-7, Sub 1214.

Exhibit 5. LBNL guidance document on estimating outage costs associated with self-healing grids.

Exhibit 6. 2009 *Estimated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, by LBNL.

Exhibit 7. DEP response to Public Staff DR 54-14.

Exhibit 8. DEP response to Public Staff DR 132-7.

Exhibit 9. DEP response to Public Staff DR 126-5.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST-BENEFIT ANALYSES, CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes. I recommend several changes to the CBAs that justify GIP programs, and I recommend that the Company take steps to improve its interruption cost estimates. I discuss these recommendations in more detail at the end of my testimony, but I summarize them here:

1. Future expenditures on GIP should be tracked and reported.
2. The Company should perform CBAs for some GIP programs that were not evaluated for cost-effectiveness, such as Distribution

Automation, DER Dispatch, and any others that the Commission deems appropriate.

3. The Company should be required to file sensitivity analyses of its CBAs, which should include, at a minimum, variance in capital costs, Operatins and Maintenance (O&M) costs, fuel and related benefits, and customer interruption costs, along with any other parameters the Commission deems appropriate.

4. The Company should consider if there is value in conducting an interruption cost study in the Carolinas that would more accurately reflect interruption costs experienced by its customers.

5. The Company should remove or modify certain benefits from its CBAs, including long duration reliability benefits, asset management benefits, and CO_2 emissions savings.

6. The Company should revise its SOG CBAs to include the effect of momentary outages as a result of automatic circuit reconfiguration.

7. The Company should revise its SOG CBA to take into account the expected reduction in vegetation-related outages resulting from the increased pace of vegetation management proposed in this proceeding.

8. The Company should consider the impact of GIP programs on costs not considered, such as materials and supplies (M&S) inventory and deferral costs, and factor those impacts (if any) into its CBAs.

9. DEP should reduce the scope of the DSDR to CVR Conversion project in order to determine lost peak-shaving benefits.

10. DEP should review its Transformer Bank Replacement and Oil Breaker Replacement programs to ensure that customers do not bear costs for unnecessary early asset replacements.

11. DEP should include the cost of repairing faults on underground lines in its TUG CBA.

12. The Commission and the Company should consider if changes to GIP cost allocations are warranted.

13. If the Commission determines that the Transmission System Intelligence program should be granted accounting deferral, DEP should be permitted to defer no more $23.7 million over the next three years.

I. Summary of GIP CBAs

Q. WHAT IS A COST-BENEFIT ANALYSIS?

A. A cost-benefit analysis is a comparative analytical tool used to evaluate whether or not a certain investment is cost-effective. Typically, a CBA compares two or more options, is performed over a fixed time period, and considers periodic expenditures and benefits throughout the time period studied. CBAs must consider the time value of money, escalation rates, and other factors that influence costs and benefits over time. Replacement costs for capital assets that have lives shorter than the CBA analysis period must also be included. Typically, estimating the costs is a relatively straightforward exercise; the challenge often lies in the quantification of benefits to offset costs. Key variables and assumptions such as capital and labor costs, escalation rates, and prices for energy and capacity underpin the calculations performed. Once the net present value of the costs and benefits has been calculated, the benefit-cost ratio (BCR) is derived by dividing total benefits by total costs.[6]

Q. YOU REFER TO COST-BENEFIT ANALYSIS AS A COMPARATIVE ANALYSIS. TO WHAT ALTERNATIVES DOES DEP COMPARE ITS GIP PROJECTS?

A. In its CBAs, the Company compares the cost of its chosen GIP programs to a “business as usual” scenario – in other words, it evaluates its selection of GIP projects relative to no new action. I do have some concerns that GIP projects were not compared to other possible actions – for example, the reliability benefits of SOG were compared to the grid as it is today, instead of other reliability improvements (such as microgrids, onsite generation, or targeted undergrounding). It is possible that more cost-effective solutions that were not evaluated exist and would provide similar reliability benefits.

[6] The use of a CBA for GIP programs is not unlike the costs and benefits contemplated under Commission Rule R8-68(c)(2)(iv). The results of the CBA, including the BCR, are not unlike the cost-effectiveness test contemplated under Commission Rule R8-68(c)(2)(v).

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF THE PUBLIC STAFF'S PROCESS FOR REVIEWING GIP CBAs.

A. The Public Staff reviewed each CBA spreadsheet provided as part of Oliver Exhibit 7. We reviewed the costs and benefits that were included in each CBA, and sent numerous discovery requests for supporting documentation, particularly focusing on obtaining a better understanding of the quantified benefits. In addition, the Public Staff met with Duke's technical subject matter experts to review the CBAs and operational aspects of the GIP programs. We questioned each benefit calculation to ensure that the assumptions underpinning the benefits were reasonable. In addition, we looked at capital cost assumptions and estimates to determine reasonableness.

Q. DID YOU FIND THE CBAs TO BE GENERALLY REASONABLE?

A. I believe the Company made a good faith effort to quantify the costs and benefits of the GIP programs. The reliability benefits, which make up a large portion of the overall GIP benefits, are difficult to quantify accurately, particularly without direct customer surveys performed by the Company. However, I have several concerns regarding the assumptions made for the CBAs that may influence the final cost-effectiveness of each program, and indeed, the entire GIP proposal. In our evaluation of the Company's deferral request, discussed in the testimony of witnesses David Williamson and Tommy Williamson, the Public Staff reviewed the cost-effectiveness of each

GIP program, taking into account the impact of several of my recommendations.

Q. CAN YOU SUMMARIZE YOUR CONCERNS FROM A COST-BENEFIT PERSPECTIVE?

A. Yes. These concerns will be discussed in more detail later in my testimony, but can be generally summarized for the entire GIP proposal as follows:

- Direct benefits from GIP programs are primarily customer reliability benefits, which make up approximately 87% of total GIP benefits. Customer reliability benefits are very difficult, if not impossible, to verify.
- The study supporting the reliability benefits may not accurately reflect outage costs incurred in North Carolina.
- Further, where these reliability benefits were broken out by customer class, approximately 97% were attributed to commercial and industrial customers, with the remaining 3% attributed to residential customers.
- Capital cost estimates were of a high-level nature with wide expected accuracy ranges, and the CBAs did not include any sensitivity analysis of capital costs to inform stakeholders of project risk.
- No sensitivity analysis of any key variables appear to have been conducted as part of the CBA process.

- Some CBAs appear to have ignored or minimized the unfavorable effects of momentary outages, as well as future investments in traditional grid maintenance programs, such as vegetation management (VM).

Q. WAS A CBA CONDUCTED FOR EVERY GIP PROGRAM?

A. No. Detailed quantitative CBAs were performed for the projects within the "Optimize" category of GIP investments.[7] No CBAs were performed for any programs within the "Modernize" or "Protect" categories.

Q. WHY DID SOME PROGRAMS NOT HAVE A CBA CONDUCTED?

A. Oliver Exhibit 6 provides a protocol for the level of study programs must undergo and provides a process for determining whether or not a CBA is required. For example, programs that are required for compliance and that are non-discretionary are exempted from a CBA. This generally covers the "Protect" category of GIP investments.[8]

In addition, there are certain factors, such as objective or subjective qualitative or quantitative benefits to the customer, Company, or third parties that may not be quantifiable but "nonetheless justify the activity,"[9]

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[7] These programs include SOG, DSDR Conversion, Transmission H&R, TUG, DTR, LDI/HIS, Transmission Transformer Bank Replacements, and Oil Breaker Replacements.

[8] These programs are also referred to as Physical and Cyber Security, representing approximately $133 million over three years, of which $68 M is allocated to DEP (NC capital budget).

[9] *See* Direct Testimony of DEP witness Oliver Exhibit 6, at 2.

which can lead to a project being considered presumptively justified. In this case, the project would not require the detailed cost-benefit analysis. This may include work that is not technically compliance work, but is essential for modern system operations.[10] These generally apply to the programs under the "Modernize" category.[11]

Finally, no CBA was filed in this proceeding for the Energy Storage or Electric Transportation programs, as the Company did not request deferral for these programs in this proceeding.

Q. ARE THERE ANY GIP PROGRAMS THAT YOU BELIEVE SHOULD HAVE HAD A CBA CONDUCTED AND DID NOT?

A. Yes. I believe the Company should have conducted a CBA for several of the programs within the "Modernize" category. Specifically, I recommend that the Company perform CBAs for the DER Dispatch Tool and the Distribution Automation program (including hydraulic to electronic reclosers, fuse replacement, and underground system automation). The DER Dispatch Tool will allow the Company more control over curtailment of third-party owned and operated solar facilities, and has an estimated cost of $2.9 million in DEP. The Distribution Automation programs I recommend for a

[10] *See* Direct Testimony of DEP witness Oliver Exhibit 5, at 2.

[11] These programs include Enterprise Communications, Distribution Automation, Transmission System Intelligence, Enterprise Applications, Integrated Systems Operations Planning, DER Dispatch Tool, and Power Electronics for Volt/VAR Control. They represent $536 million over three years, of which $228 million is allocated to DEP (NC capital budget).

CBA consist of an accelerated deployment of certain automated devices that allow the Company more control over distribution system power flows. The three components of the program have estimated capital costs of approximately $75.9 million in DEP's North Carolina jurisdiction. While a CBA may not necessarily change the conclusions reached by Public Staff witnesses Tommy Williamson and David Williamson regarding the Company's deferral request, they are important in determining whether these programs are reasonable and prudent in future cost recovery proceedings.

Q. HOW DID THE COMPANY JUSTIFY NOT PERFORMING A CBA FOR EITHER OF THESE PROGRAMS?

A. Company witness Oliver classifies both the DER Dispatch Tool and the Distribution Automation program as "rapid technology advancement work" needed to modernize the grid. They define this type of work as including the following types of work and activities:

> [D]eploying new system-wide communications devices so that the transmission and distribution system can communicate back to us and with each other, <u>replacing pneumatic and manually actuating equipment with modern electronic and intelligent equipment that is self-actuating and self-correcting</u>, and installing advanced system intelligence devices that will allow our underground and overhead assets to proactively report their condition status and potential problems before they manifest into equipment failures. [12]

[12] Direct testimony of DEC witness Oliver, at 33-34 (emphasis added).

The Company further states that programs in the "Modernize" category will be "deployed and selected in a cost-effective manner."[13] The Public Staff notes that the SOG and IVVC programs, for which DEP did perform a CBA, consist of deploying modern electronic and intelligent equipment that is self-actuating.

Without a proper CBA to determine the benefits and costs of these programs, it is impossible for the Company to know whether or not these programs are being deployed in a cost-effective manner.

Q. DID THE COMPANY ANALYZE THE SENSITIVITY OF ITS CBAs TO CHANGES IN KEY VARIABLES?

A. No. The CBAs provided in Oliver Exhibit 7 did not include or discuss any sensitivity analyses. I am concerned that lack of sensitivity analyses included in the CBAs masks the significant uncertainty in key underlying assumptions.

Q. WHAT IS A SENSITIVITY ANALYSIS AND WHY ARE THEY IMPORTANT?

A. Each CBA performed by the Company includes many assumptions, such as discount and escalation rates, capital costs, interruption cost estimates, etc. Many are subject to significant uncertainty. A sensitivity analysis would select key assumptions (and combinations of assumptions) and present a

[13] *Id.* at 34.

range of CBA results based upon varying those assumptions, identifying the risks to ratepayers of cost overruns or benefit shortfalls. Sensitivity analyses are useful for the utility, regulators, and stakeholders, in that they can show how robust a GIP program's CBA is to changes in key variables. The lack of sensitivity analysis was identified by Commission Staff in Virginia as a shortcoming of Virginia Electric and Power Company's (VEPCO) grid transformation proposal.[14]

Q HAS THE PUBLIC STAFF TRADITIONALLY REQUIRED SENSITIVITY ANALYSES FOR PROPOSED INVESTMENTS?

A. The use of sensitivity analyses is required by Commission Rule R8-60(g) for Integrated Resource Plans (IRPs) when evaluating resource options, indicating its importance to the Commission. In some cases, the Public Staff has identified the need for additional analysis of key assumptions.[15] In this proceeding, the scale of the proposed benefits from GIP is almost without precedent, and we believe more analysis is necessary to ensure that the risks to ratepayers are fully explored.

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[14] *See* VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 26-27.

[15] For example, in the Public Staff's February 17, 2017 comments on the 2016 IRPs, we recommended the utilities evaluate the risks and required costs for subsequent license renewals at their nuclear plants. *See* Docket No. E-100, Sub 147, Comments of the Public Staff, at 34-35. We also request sensitivity analyses as part of our discovery and investigation process.

II. GIP Program Benefits

A. Overview of GIP Benefits

Q. PLEASE DESCRIBE WHAT BENEFITS WERE CONSIDERED IN THE CBAs.

A. The Public Staff divided benefits within the CBAs into two broad categories: operational benefits and customer benefits. In this context, operational benefits describe benefits which accrue to DEP and have the potential to reduce future operating costs. Thus, benefits in this category can be expected to reduce future customer bills. The subcategories of operational benefits include:[16]

1. Outage restoration – cost savings attributable to a reduction in outage repair costs (i.e., truck rolls) as a result of fewer outages occurring.
2. Vegetation management – lower costs due to less vegetation management required (in the Targeted Undergrounding CBA only).
3. Asset management – these benefits reflect that for some programs, assets already deployed are replaced before they would typically be scheduled for replacement. Thus, the avoided cost of replacing these devices in the future is considered a program benefit.

[16] Unlike DEC programs, no DEP programs claim an avoided capacity benefit.

4. Fuel and related – these benefits include avoided fuel, reagent, and emission costs (excluding CO_2), reduced variable O&M, and avoided start-up costs as a result of GIP programs.

Customer benefits accrue to the customer but are generally difficult to quantify and are not expected to reduce future utility operating expenses, which means these benefits will not directly cause future rate reductions. The subcategories of customer benefits include:

1. Reliability – these are monetized estimates of the benefits customers realize by having more reliable power. The reliability improvement estimates have been quantified using a 2015 Lawrence Berkeley National Laboratory (LBNL) report entitled *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*[17] (LBNL Report, attached as Exhibit 1), which will be discussed in more detail later in my testimony.

2. CO_2 – DEP uses its projections of a future carbon price from its 2019 Integrated Resouce Plan (IRP) to quantify the cost savings from reduced CO_2 emissions. This benefit is directly proportional to the reduction in carbon-emitting generation.[18]

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[17] Sullivan, M.J., J. Schellenberg, and M. Blundell. (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

[18] CO_2 benefits have been separated from utility operational fuel and fuel related benefits because, unlike SO_2 and NO_X, there currently are no costs associated with CO_2 emissions.

3. Distributed Energy Resource (DER) Enablement – the benefit of enabling additional DER to be added compared to the base case, primarily due to increased distribution line capacity in the SOG program.

These benefits, and their inclusion in each program's CBA, are summarized in Table 1 below. The Public Staff did not review the Company's claimed IMPLAN benefits, which are indirect and societal benefits estimated through economic modeling.[19]

[19] IMPLAN is an economic input-output model that estimates the economic impact to communities based upon interdependencies between economic sectors. The Public Staff did not review these benefits because indirect benefits such as those estimated from IMPLAN are not traditionally considered in cost benefit analyses for prudence review and program approval.

1 *Table 1: Benefit Categories of GIP CBAs. "Yes" indicates this benefit is quantified in the GIP*
2 *CBA.*

GIP Program	Operational					Customer		
	Outage Restore	Veg Mgmt	Asset Mgmt	Fuel + Related	Avoided Capacity	Reliability	CO_2	DER Enablement
SOG				Yes	Yes	Yes	Yes	Yes
IVVC (DEC)				Yes	Yes		Yes	
DSDR Conversion				Yes			Yes	
T-Transformer Bank Replacement			Yes			Yes		
DTR	Yes					Yes		
Transmission H&R	Yes		Yes			Yes		
Oil Breaker Replacements			Yes			Yes		
Transmission Line Projects (DEC)						Yes		
Transmission Line Projects (DEP)						Yes		
LDI / HIS						Yes		
TUG	Yes	Yes	Yes			Yes		

Q. WHY HAVE YOU DIVIDED BENEFITS INTO OPERATIONAL AND CUSTOMER CATEGORIES?

A. We performed this analysis to better understand which GIP programs would be likely to pass a utility cost test (UCT),[20] if all cost and benefit estimates are accurate. A program that still had a BCR greater than one even after removing the customer benefits would be indicative that it would reduce customer rates over the long term, which is an important consideration to the Public Staff for such large utility investments.

In addition, operational benefits from GIP programs are measurable and can generally be validated after GIP program implementation with the proper monitoring and reporting requirements. Interestingly, the Public Staff found one example of another state utiliy commission requiring that grid modernization costs be netted against estimated operational benefits, to reduce cost recovery rate impacts.[21]

However, I do not believe it is possible for DEP to verify their estimates of customer benefits. While reliability improvements can and should be

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[20] This test is commonly used in energy efficiency program evaluations, and reflects the program costs and benefits from the utility's perspective. The UCT is used for evaluating the cost effectiveness of Energy Efficiency and Demand Side Management programs under Commission Rule R8-68(c)(2)(v).

[21] *See* Duke Energy Ohio's request to recover "SmartGrid" costs, Case Record 10-2326-GE-RDR, *Opinion and Order* of the Public Utilities Commission of Ohio, filed June 13, 2012, at 14-17, 26. *Available at* https://dis.puc.state.oh.us/TiffToPDf/A1001001A12F13B45127H62832.pdf (last accesssed March 9, 2020).

measured following GIP implementation, quantifying those benefits in terms of cost savings to customers is extremely difficult, if not impossible.

Q. WOULD ANY OF THE GIP PROGRAMS PASS A UTILITY COST TEST?

A. Yes. DEP witness Oliver's Exhibit 8 shows that when all benefits are included, the total "Optimize" portfolio of projects claims a combined BCR of 4.7; only one project, the Transformer Bank Replacements, has a BCR less than 1.0. However, if only the operational benefits are considered, the combined BCR of the "Optimize" portfolio falls to 0.48, and the only programs that pass a UCT test with a BCR greater than 1.0 are the DSDR Conversion and Transmission H&R (substation flood mitigation in DEP). The inclusion of customer benefits in the GIP CBAs, and particularly customer reliability benefits, significantly influence their cost-effectiveness.

Q. PLEASE SUMMARIZE THE MAGNITUDE AND DISTRIBUTION OF GIP CBA BENEFITS.

A. Figure 1 below visually summarizes the program costs, operational benefits, and customer benefits for all GIP CBAs in DEP's and DEC's North Carolina territories.[22] These figures were drawn from the individual CBAs filed in Oliver Exhibit 7 and were validated against the summary provided in Oliver Exhibit 8. Total CBA program costs are estimated to be $1.98 billion, consisting of $1.90 billion in capital costs and $0.8 billion on O&M costs.

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[22] All figures in NPV, 2019 dollars.

Total CBA program benefits are estimated at $9.24 billion, consisting of approximately $8.3 billion in customer benefits and $942 million in operational benefits.

Several conclusions can be drawn from reviewing the costs and benefits split out in this way: first, the total program costs are twice as large as the operational benefits, indicating that as a whole, the GIP proposal would not pass a UCT for cost-effectiveness. Second, operational benefits only account for approximately 10% of the total benefits claimed. Finally, the vast majority (approximately 87%) of all benefits from the proposed GIP program are attributed to customer reliability.

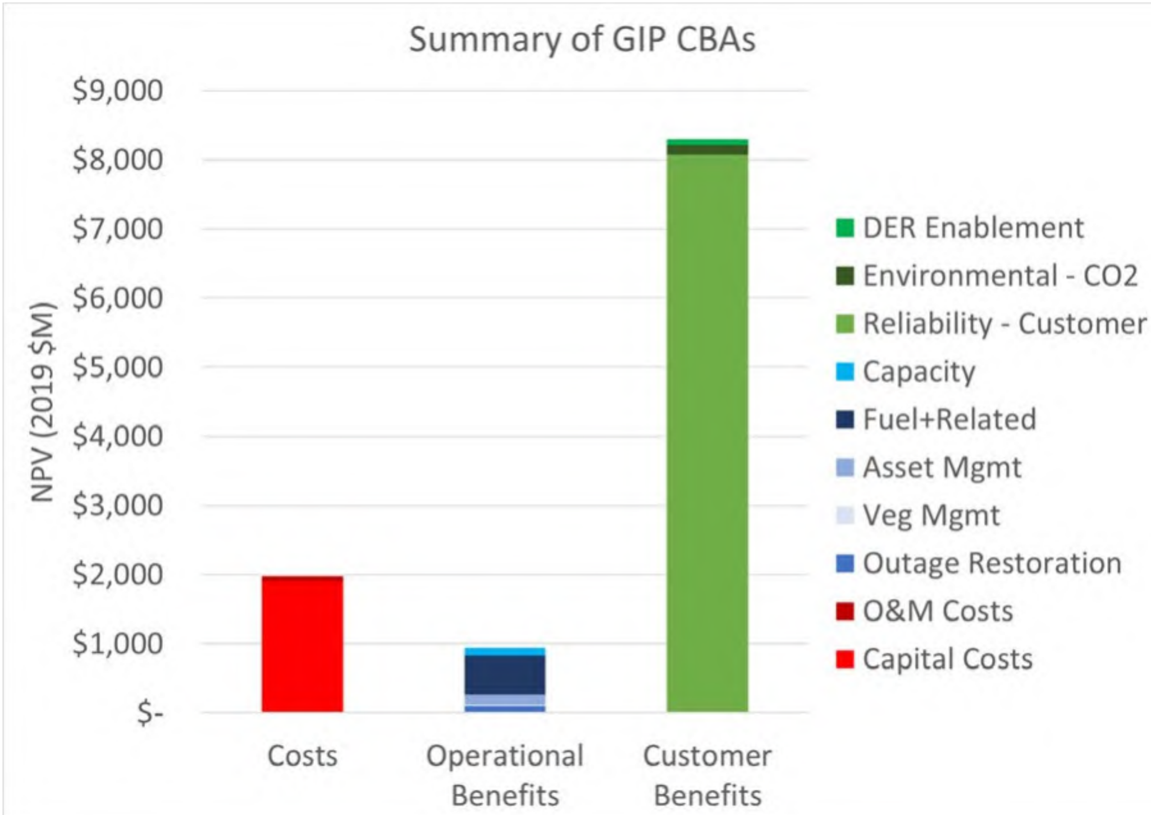

Figure 1: Summary of GIP CBA Costs and Benefits

B. Customer Reliability Benefits

Q. CAN YOU ELABORATE ON THE METHOD USED TO QUANTIFY CUSTOMER RELIABILITY BENEFITS?

A. Yes. These benefits have been quantified in two steps: first, the reduction in outages as a result of the GIP program (quantified as Customer Interruptions, or CI) is estimated. The methodology for doing so varies by CBA, but generally this process relies on reviewing historical outage data to establish a 'baseline' CI, and then attempting to determine what types and quantities of outages might be avoided if the GIP program is successful.

Next, the cost per outage is quantified using the LBNL Report, specifically Table ES-1, which is presented below as Table 2. In every CBA but for the Integrated Volt-VAR Control (IVVC) and DSDR Conversion (which do not include reliability benefits), the Company uses the "Cost per Event" figures from this table, adjusted for inflation, to quantify the benefits from the estimated improvement in CI caused by the GIP program being studied. The customer classes studied in the LBNL Report are residential, small commercial and industrial (C&I), and medium and large C&I.[23] This LBNL report will be addressed in detail later in my testimony.

Table 2: Estimated Interruption Cost per Event from the LBNL Report, page xii.

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

[23] Small C&I represents C&I customers with less than 50 MWh of annual usage; medium and large C&I represent C&I customers with 50 MWh or more of annual usage.

Q. BEFORE ADDRESSING THE LBNL REPORT, DO YOU HAVE ANY CONCERNS WITH HOW THE COMPANY HAS QUANTIFIED THE REDUCTION IN OUTAGES AS A RESULT OF GIP?

A. Yes, I have identified two main problems: (1) certain CBAs appear to lack a consideration of the impact of VM, and (2) the SOG CBA appears to ignore the costs of increased momentary outages during SOG events.

Q. PLEASE DESCRIBE HOW VEGETATION MANAGEMENT AFFECTS OVERALL SYSTEM RELIABILITY.

A. Witness Oliver describes the Company's VM program, which is designed to "improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system."[24] The Company proposes an increase of $7.2 million[25] to its rates in this proceeding to address contractor rate increases, as well as to cover the mileage increase in the plan, which is higher than the mileage completed in the test year due to the impact of several major storms on routine VM miles trimmed.[26] While the Company has not quantified expected improvement in system reliability metrics as a result of its VM program, vegetation-related outages have accounted for 38% and 33% of DEP's 2019 North Carolina SAIDI and SAIFI metrics,

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[24] Direct testimony of Oliver, at 7.

[25] *See* Direct testimony of Smith, Pro forma Adjustment NC-2702, distribution and transmission.

[26] Direct testimony of Oliver, at 23.

respectively. The Public Staff agrees with DEP witness Oliver that the VM program will result in some level of reduced vegetation-related outages; however, we acknowledge that there is not a realistic amount of VM work that can be done to reduce these numbers to zero.

Q. HOW COULD OUTAGE REDUCTION BENEFITS BE IMPACTED BY VEGETATION MANAGEMENT?

A. I believe it is likely that the Company's VM plan will reduce the number of avoided outages that the Company is currently projecting from its GIP programs. The estimated reduction in CI from each GIP program is largely derived from the difference between historical outage rates (the 'baseline') and assumptions about how a particular GIP program will reduce outages. If vegetation-related outage rates decline over the next five years due to DEP's VM plan, then the 'baseline' used in the GIP CBAs will be overstated, causing the projected CI reduction, and the estimated benefits, to similarly be overstated.

Q. HAS THE COMPANY ATTEMPTED TO MITIGATE THE INFLUENCE OF THIS FACTOR?

A. Yes. In some instances, the Company made efforts to control for this by only including historical outages of a certain type in its baseline (for example, the Transformer Bank Replacement CBA only looked at historical outages initiated by a failed transmission transformer equipment). The outage history database maintained by the Company includes comments and outages that are classified by cause. It appears that good faith efforts were made, in some of the CBAs, to remove vegetation-related outages from estimates of outage reductions due to GIP.

Q. ARE THERE ANY CBAs THAT MAY NOT HAVE APPROPRIATELY INCLUDED THE IMPACT OF FUTURE VEGETATION MANAGEMENT IMPROVEMENTS?

A. Yes. For some programs, the mitigation process required some subjectivity or was not done, and a high baseline bias cannot be ruled out. One example is the Distribution Transformer Retrofit (DTR) CBA, in which the baseline outage information required a complex series of steps to scrub the data, including a "contextual search of comments" to determine if the outage was due to an un-retrofitted transformer.[27] Errors in entering or searching the comments could lead to a high (or low) bias in baseline reliability if vegetation-related outages were inadvertently included in (or excluded from) the baseline. Another example is TUG, which also uses historical outage data to estimate customer reliability benefits of $1.9 billion. CBAs are comparative analyses, looking at the merits of one course of action over another. The TUG CBAs compare undergrounding to no action; instead, they should compare undergrounding to the impact of reduced outages from the Company's VM plan to avoid overstating customer reliability benefits.

[27] *See* DEC response to PS DR 133-7, attached as Thomas Exhibit 2.

Of particular concern are the outage reduction estimates from SOG. A key factor in the calculations supporting estimated CI and Customer Minutes Interrupted (CMI)[28] reductions on SOG circuits is the "faults per mile" on the DEP distribution system; this factor divides the total number of outages on the distribution system greater than five minutes, regardless of cause, by the total number of feeder backbone[29] miles. As all vegetation-related outages are included in the faults per mile calculation (including those outages that might be avoided through the Company's VM plan), it is likely that this figure is biased high, leading to inflated estimates of reliability benefits from SOG.

Q. DO YOU BELIEVE THAT THE FAULTS-PER-MILE FIGURE USED IN THE SOG CBA IS OVERSTATED FOR DEP?

A. While it is possible, I do not believe the impact in DEP will be as pronounced as the impact in DEC. In my testimony in the DEC case, Docket E-7, Sub 1214, I highlighted the fact that DEC had thousands of miles of backlog that they planned to aggressively target over the next five years.[30] However, DEP has far less – only approximately 61 backlog miles.[31]

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[28] CI is generally used to quantify the reduction in the number of outages. CMI is used to determine the typical duration of outages, which allows the Company to select the appropriate Cost per Event from the LBNL Study.

[29] Duke describes the feeder backbone of a circuit as: "3-phase, unfused line sections, not protected by a reclosing device of 200 amps per phase or less." *See* DEC response to PS DR 133-13, attached as Thomas Exhibit 3.

[30] *See* testimony of Thomas in Docket No. E-7, Sub 1214, at 24.

[31] *See* the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson in this Docket, at 10.

Q. DO YOU HAVE ANY RECOMMENDATIONS TO REDUCE THE IMPACT OF FUTURE VEGETATION MANAGEMENT ON GIP CBAs?

A. Yes. Regarding DTR and TUG, the Company should carefully review the sources of outage data and the methods utilized to mitigate this issue for each CBA, along with the estimated reliability impacts of improved VM. It should then be required to update the Commission and GIP stakeholders on the process and results of its review, including a revised CBA.

With respect to SOG, the Company should review its calculation of the faults-per-mile metric by removing a reasonable percentage of vegetation-related distribution outages from its baseline, proportional to the Company's anticipated reduction to vegetation-related outages as a result of its VM plan over the next five years. If the Company does not anticipate that its VM plan will lead to a reduction in vegetation-related distribution outages relative to the 2018 baseline used in its CBAs, it should plainly state as such and provide an explanation to the Commission.

Q. MOVING TO YOUR NEXT CONCERN, PLEASE EXPLAIN THE PROBLEM WITH MOMENTARY OUTAGES IN THE SOG CBA.

A. To begin, I will briefly explain how SOG improves reliability. First, it splits a circuit into segments that are separated with automatic switches or reclosers (SOG Automation). Next, it interconnects with an alternate feeder, creating a "loop" where power can now come from both ends of the line (SOG Connectivity); capacity of the distribution lines, the original feeder, and the alternate feeder substations are increased so that either substation can supply power to the majority[32] of the combined circuit in the event of a fault (SOG Capacity).[33] Figure 2 below illustrates a SOG circuit with three segments, tied into an alternate substation with a normally open line.

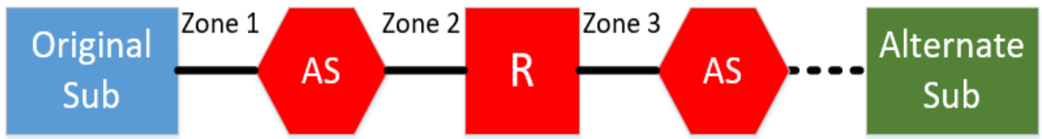

Figure 2: Illustration of a SOG circuit. AS = automatic switch; R = recloser. The dotted line represents an intertie to an alternative substation that is normally open unless a fault occurs.

In a hypothetical scenario, assume a fault occurs in Zone 2, which causes a sustained outage. The automatic sensing and switching devices detect the segment of the circuit where the fault occurred, isolate it from the remainder of the circuit, and begin feeding power in from the alternate feeder. In its CBA, the Company assumes that customers in Zone 2 experience a sustained outage, and customers in Zones 1 and 3 experience no outage. I believe the Company has correctly quantified these benefits for Zone 2 customers; however, while customers in Zones 1 and 3 avoid a sustained outage, they will experience a momentary outage. This is because it can take up to two minutes for the SOG system to locate and

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[32] The increased capacity of SOG circuits is designed so that up to 70% of the companion circuit's load can be carried during 90% of the annual hours.

[33] SOG Automation, SOG Connectivity, and SOG Capacity are three components of SOG. The fourth is Advanced Distribution Management System, which coordinates the other components.

isolate the fault and connect the alternate substation in a way that will ensure adequate paths for power flows.[34] During this fault isolation and circuit reconfiguration activity, customers in Zones 1 and 3 will experience a "new" momentary outage that may last significantly longer than the momentary blinks that typically accompany circuit breaker and recloser activities. The costs of these momentary outages are not included in the Company's CBA. Similar concerns were expressed by Virginia Commission Staff in its recent comments on the VEPCO Grid Transformation Plan.[35] In that proceeding, the Virgina State Corporation Commission (SCC) denied portions of VEPCO's grid hardening proposal, a proposed category of grid modernization which included a program analogous to SOG (referred to as self-healing grid), because the record did not "support the need for this level of costs to customers when the purported gains in reliability are speculative and not targeted to the worst performing locations."[36]

Q. DO CUSTOMERS INCUR COSTS FOR MOMENTARY OUTAGES?

A. Yes. The LBNL Report quantifies these costs. In fact, the SOG CBA includes $282 million in customer reliability benefits attributed to a reduction in the number of <u>momentary</u> outages, based upon a Company assumption

[34] DEC Response to PS DR 179-4, attached as Thomas Exhibit 4.

[35] *See* VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 12-15.

[36] *See* VA Docket No. PUR-2019-00154, Final Order of the State Corporation Commission, at 23. The SCC did not make a specific determination on the validity of Virginia Commission Staff's concerns regarding momentary outages.

that for every one sustained outage, there are 1.5 momentary outages. It is not reasonable for the Company to include the benefits of avoided momentary outages, while at the same time ignoring the costs of increased momentary outages.

Q. DO THE AUTHORS OF THE REPORT IDENTIFY THIS ISSUE OF MOMENTARY OUTAGES?

A. Yes. The Interruption Cost Estimator (ICE) Calculator[37] website, under the documentation tab, has published a guide, "Using the ICE Calculator for FLISR [Fault Location Isolation and Service Restoration] Reliability Improvement Value," attached as Thomas Exhibit 5. FLISR is the automatic reconfiguration of distribution circuits, and is similar to the Company's proposed SOG program. Within this document is a discussion of how the outage benefit estimates generated for FLISR / SOG must be adjusted to account for momentary outages. In the example provided, failing to account for momentary outages as I have described could overstate benefits by about 50%.

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[37] The ICE Calculator is an online tool that uses the econometric model from the LBNL Report to generate interruption cost data using specified input parameters. It can be accessed at www.icecalculator.com.

Q. HOW DOES THE COMPANY EXPLAIN THE EXCLUSION OF THESE MOMENTARY OUTAGES?

A. Witness Oliver explains the Company's position, which is that the "addition of SOG adds the faster restoration of un-faulted sections and does not increase momentary outages."[38] While the Public Staff agrees that SOG will reduce both restoration times and the number of customers affected by a sustained outage, I disagree regarding the momentary outages. As an example, consider a sustained fault on a circuit before and after SOG, shown below in Figure 3. The rapid opening and closing of the circuit immediately following the fault is caused by the upstream breaker or recloser opening and attempting to reclose to clear the fault; these faults start as "momentary blinks" and, in the Before SOG case, can culminate in a sustained outage if the fault remains. However, in the After SOG case, the "momentary blinks" are followed by a "fault isolation and circuit reconfiguration" momentary outage, which can last up to two minutes. When I discuss a "new" momentary outage, this is what I am referring to.

[38] *See* Docket No. E-7, Sub 1214, Rebuttal Testimony of Oliver, at 30.

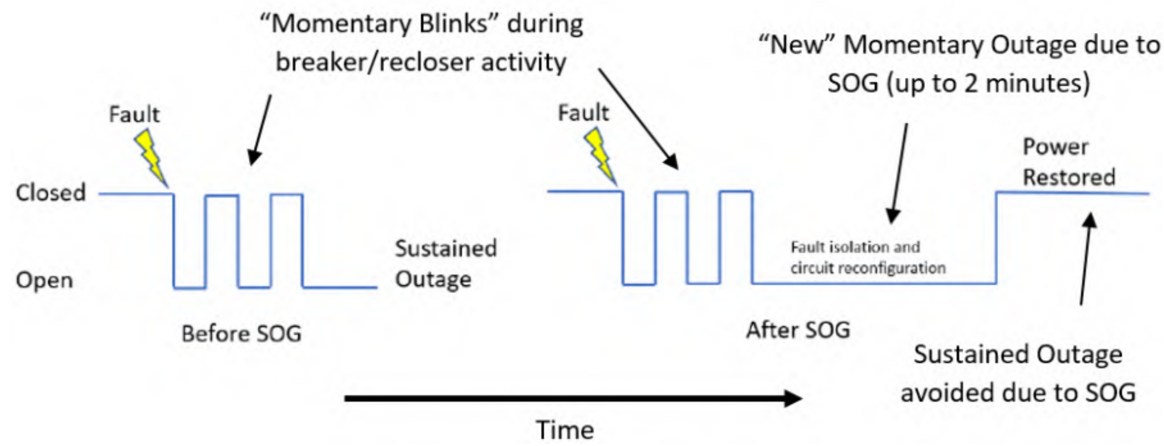

Figure 3: SOG circuit state over time following a non-temporary fault. Adapted from Reubttal testimony of witness Oliver in Docket No. E-7, Sub 1214, at 31.

Q. DO YOU BELIEVE IT IS STILL APPROPRIATE TO INCLUDE THE IMPACT OF THE "NEW" MOMENTARY OUTAGE IN THE SOG CBA?

A. Yes. The Company, in performing its CBAs for SOG, appears to group these "momentary blinks" and the "fault isolation and circuit reconfiguration" outage as a single momentary outage, thus eliminating the need to consider the latter's impact. However, the CBA is a comparative analytical tool, and the purpose is to specifically isolate the change that occurs due to the program being studied. It is wholly appropriate to exclude the cost of the "momentary blinks" from both the base case and the change case in the Company's CBAs, as they occur with and without SOG. However, the "new" momentary outage during fault isolation and circuit reconfiguration does not exist in the base case, and therefore must be considered in the change case, whether or not the Company groups this outage in with the momentary blinks for outage reporting purposes. I recommend that the benefits of the “Sustained Outage avoided due to SOG” be offset by the costs associated with the “new” momentary outage.

Q. HOW SIGNIFICANT ARE THESE EFFECTS?

A. It depends on the circuit. Generally, the Company assumes that the reduction in CI relative to the baseline is equal to the inverse of the number of segments; in other words, three segments reduce the CI by 33% and ten segments reduce the CI by 90%, reflecting the ability of SOG to confine a sustained outage to a single segment. As the number of segments increases, the number of customers affected by each interruption (CI) decreases; yet not all customers avoid an interruption, as the Company assumes. The customers who do not experience a sustained outage due to SOG will nonetheless experience a “new” momentary outage.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING MOMENTARY OUTAGES IN THE SOG CBA?

A. Yes. The customer reliability benefits associated with SOG should account for momentary outages that occur during circuit reconfiguration events. The CBA should reflect that for some customers, sustained outages are not eliminated entirely, but rather become momentary outages. Because the Company made the same assumptions when it quantified momentary outage benefits, these should be similarly reduced.

Q. HAS THE PUBLIC STAFF ATTEMPTED TO ESTIMATE THE IMPACT OF ITS PROPOSED CHANGES?

A. Yes, although a full recalculation of the per-circuit CI and CMI savings should be performed by the Company to verify. Using the SOG CBA spreadsheet, I first estimated the cost of the momentary outages that were not included by the Company, assuming that the customers who avoid a sustained outage experience a momentary one. Because the LBNL Report estimates that the cost of a sustained outage is greater than the cost of a momentary outage, SOG is still a net benefit to customer reliability.

Next, I eliminated the avoided momentary outage benefit that was included by the Company to reflect that all customers experience some momentary outages during circuit reconfiguration.[39] Finally, I subtracted the estimated cost of momentary outages from the remaining outage benefit. Based upon my analysis, I believe that accounting for the effect of momentary outages could reduce the reliability benefits of SOG by approximately 51%, or $471 million, which is consistent with the LBNL FLISR document. The Company should revise its SOG CBA to validate this result.

[39] The LBNL Report considers all outages under 5 minutes to be "momentary."

C. The LBNL Report and Interruption Cost Estimates

Q. TURNING NOW TO THE LBNL REPORT, PLEASE PROVIDE A GENERAL OVERVIEW OF REPORT'S METHODOLOGY.

A. The LBNL report was an update to a similar 2009 report,[40] which was a meta-analysis performed by the consulting group Nexant for LBNL (2009 LBNL Report, attached as Thomas Exhibit 6). The 2009 LBNL Report analyzed the results from "28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005." Because these studies utilized very similar methodologies to estimate interruption costs (including direct cost estimation[41] or willingness-to-pay (WTP) / willingness-to-accept (WTA) surveys[42]), these results were integrated into a single econometric dataset that was used to create an econometric regression model to estimate outage costs to customers.[43]

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[40] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[41] Direct cost estimation surveys (also known as direct worth) typically ask respondents to quantify the economic losses due to a hypothetical power outage using a worksheet. These are more typically sent to non-residential customers.

[42] Willingness-to-pay surveys typically ask customers questions designed to understand what they would be willing to pay to avoid a hypothetical outage. Willingness-to-accept surveys typically ask customers questions designed to understand how much they would be willing to accept to be indifferent to an outage. These are more typically sent to residential customers.

[43] The authors of the 2009 LBNL Report discuss the various survey methodologies in Appendix B of the Report.

The 2015 LBNL Report updates this work with two additional interruption cost studies (one each from a southeastern and a western electric utility), which improves the ability of the ICE Calculator to estimate the cost of outages longer than eight hours, a limitation of the 2009 LBNL Report. It also makes refinements to the econometric model and the associated ICE Calculator, such as reducing the number of variables needed, thus easing data burdens associated with using the ICE Calculator.

Q. ARE THERE ANY CAVEATS NOTED IN THE LBNL REPORT?

A. Yes, there are several caveats either explicitly stated or implied in both the 2009 LBNL Report and the 2015 LBNL Report, some of which highlight the Public Staff's concerns with the $8 billion in customer reliability benefits claimed in DEP's and DEC's North Carolina CBAs. Broadly, these concerns include: (1) limitations when quantifying outages longer than 16 hours; (2) possible high bias on outage cost data due to the nature of the studies used; and, (3) the lack of DEP-specific outage surveys used to create the LBNL Report. These issues highlight the Public Staff's primary concern with the quantification of these benefits, which is the Company's direct application of the national level outage costs. I would also note that some of these issues have been raised in other jurisdictions where the LBNL Report has been used to quantify customer reliability benefits, most recently in Virginia.[44]

Q. BEFORE YOU DETAIL THE PUBLIC STAFF'S CONCERNS WITH THE COMPANY'S DIRECT APPLICATION OF THE LBNL BENEFITS, DO YOU HAVE ANY THOUGHTS ON HOW THEY MIGHT BE RESOLVED?

A. Yes. I will summarize them here, with additional explanation to follow. Broadly, my concerns center around the fact that the interruption cost estimates are not certain enough, not region-specific enough, and are not sufficiently verifiable to be considered in a prudence evaluation of proposed GIP investments.[45] DEP can improve the accuracy and reliability of these results in a few ways.

First, I would recommend that the Company reach out to LBNL to see how their work might be furthered to resolve some of the concerns. For example, the researchers may highlight how the Company could design an efficiently conducted, targeted interruption cost study in its jurisdictions to provide new region-specific data, which could be used in a new Southeastern interruption cost model.

[44] *See* VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 6-27.

[45] This concern as also raised in Virginia by the Attorney General in their review of the Dominion Grid Transformation Plan. *See* VA Docket No. PUR-2019-00154, Direct Testimony and Exhibits of D. Scott Norwood, at 10.

In the interim, I recommend that DEP coordinate with other Southeastern utilities that provided interruption surveys to LBNL (e.g., Southern Company) to see if they will share the interruption cost surveys they provided to LBNL. DEP could then adjust the LBNL figures to take into account nearby utilities' experience. DEP could also conduct limited direct cost estimation surveys of its C&I customers to validate against the LBNL Report.

I also recommend that the Company reduce or remove the benefits associated with outages over 24 hours until these costs can be better understood. The Company also should perform sensitivity analyses on the cost per event figures in order to demonstrate to the Commission how the CBA results are influenced by outage cost estimates.

Q. CAN THE OUTAGE DATA IN THE LBNL REPORT BE USED TO QUANTIFY LONGER TERM OUTAGES?

A. The authors of the report caution against using the outage cost data to estimate longer-term outages. While the LBNL Report does attempt to better quantify the costs of outages lasting longer than 8 hours with the addition of new outage cost surveys, the report warns that "the estimates in this report are not appropriate for resiliency planning."[46] The results in the LBNL Report are truncated at 16 hours due to the relatively few number of

[46] LBNL Report, at 48.

observations beyond 12 hours. The LBNL Report states that for consideration of "long duration outages of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered."[47]

Q. DESPITE THESE CAVEATS, DOES THE COMPANY USE THE LBNL REPORT TO ESTIMATE THE VALUE OF LONGER OUTAGES?

Yes. The Company linearly extrapolates the LBNL Report outage costs for outages lasting longer than 16 hours. Linear extrapolation describes the process of using the outage cost dataset (outage cost as a function of duration) to estimate outage costs for durations longer than the maximum provided in the dataset, assuming that outage costs increase linearly with duration. This was typically done to quantify the benefits of reduced Major Event Day (MED) outages.[48]

For example, the Long Duration Interruptions / High Impact Sites (LDI/HIS) and the Transmission Hardening and Resiliency (Transmission H&R) CBAs quantify the costs of outages of up to 87 hours. The Distribution Transformer Retrofit (DTR) CBA quantifies MED outages up to 20 hours. Some of the Targeted Undergrounding (TUG) CBAs quantify avoided MED outages

[47] *Id.* at 49.

[48] MED outages are typically the result of major events, such as hurricanes, ice storms, severe thunderstorms, and other events.

significantly longer than 12 hours, in some cases as long as 30 or more hours.

Q. DOES THE PUBLIC STAFF HAVE CONCERNS WITH THE COMPANY'S LINEAR EXTRAPOLATION METHODOLOGY?

A. Yes, I have concerns that the customer reliability benefits associated with long-duration MED outages may be overstated. Figure 4 from the LBNL Report below illustrates the risks in quantifying outage durations longer than 16 hours. This data contributes to the total outage costs per event used in the Company's CBAs, which is affected by the timing of each individual outage assumed in the ICE Calculator.

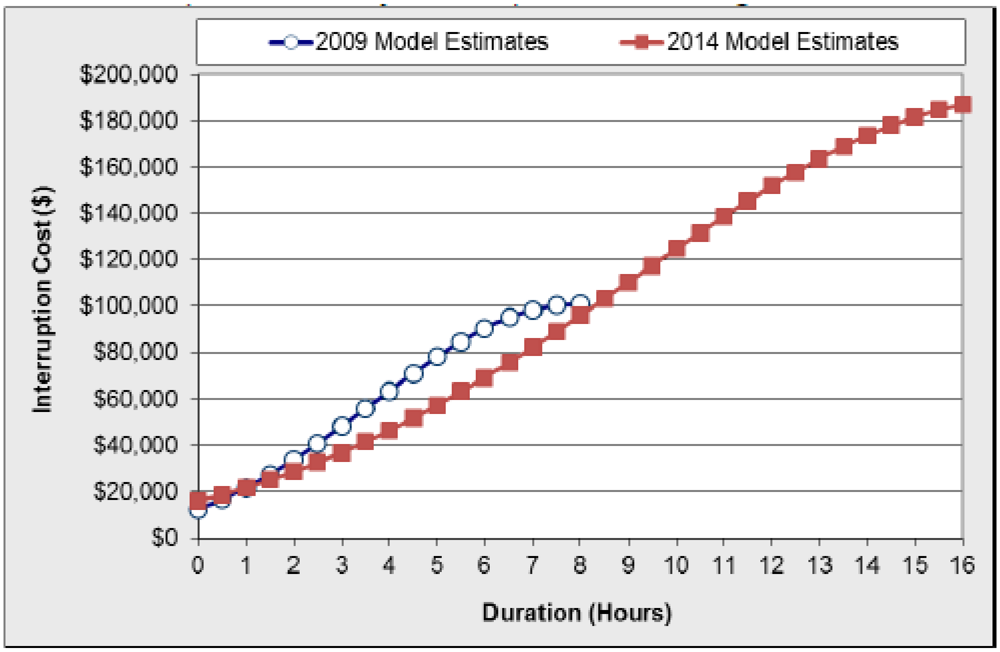

Figure 4: Estimated Customer Interruption Costs (2013 $) by Duration and Model - Summer Weekday Afternoon, Medium and Large C&I. Source: Figure 3-1 from LBNL Report.

The outage cost curve for Medium and Large C&I customers in the summer weekday afternoon, as a function of outage duration, exhibits S-curve characteristics, with outage costs appearing to increase at a slower rate after outage durations of approximately 12 hours.[49] A linear interpolation such as that used by the Company could potentially overstate outage costs for long-duration outages, which could have a significant impact on the CBA results. For example, $1.56 billion in customer reliability benefits (across DEP's and DEC's NC service territory) in the LDI/HIS CBA come from quantifying long duration MED outages, representing 84% of the total

[49] The same trend is exhibited by Small C&I customers (*see* LBNL Report, figure 4-1) and, to a lesser extent, Residential customers (*see* LBNL Report, figure 5-1).

benefits quantified in the LDI/HIS CBA and 20% of the total benefits quantified across all GIP CBAs.

Q. IS IT THE PUBLIC STAFF'S POSITION THAT OUTAGES LONGER THAN 16 HOURS DO NOT HAVE A COST TO CUSTOMERS?

A. No. Clearly, outages of a sustained duration have costs imposed on customers. However, I have concerns that the methodology used by the Company to estimate those costs, which the authors of the LBNL Report decline to estimate, may actually overstate the cost to customers. I recommend that outage costs for events lasting longer than 24 hours should be either validated by the Company through surveys, reduced by some reasonable factor, or capped at the outage costs associated with a 16 hour outage, the highest costs presented in the LBNL Report.

Q. IS IT POSSIBLE THAT THE OUTAGE COSTS IN THE LBNL REPORT COULD BE INACCURATE DUE TO THE UNDERLYING DATA?

A. Yes. The authors of the report acknowledge that the data used in their analysis came from interruption cost data studies performed by individual utilities; these utilities performed their study in such a way as to "focus on periods of time when interruptions were more problematic for that region."[50] Since each region has different outage distributions (by season and time of day), a bias in the timing of outages studied from a particular region could

[50] 2009 LBNL Report, at 48, Thomas Exhibit 6.

skew the results. For example, a southwestern utility might structure its WTP surveys to focus on outages during the hot summer months when customers are most likely to highly value reliable power; or a Midwestern utility facing pressure to keep C&I rates low might focus on the cost of outages to those customers at the expense of residential customers.

Q. WHAT IMPACT MIGHT THIS HAVE ON OUTAGE COSTS IN THE LBNL REPORT?

A. In both cases, the WTP surveys might return higher outage costs than if they had been structured to cover all customers and all times of day. The effects of this bias could be reduced if a significant portion of the utility study data was provided from utilities with customer and regional characteristics similar to the Company's jurisdictions; but without the underlying studies, it is impossible to understand how this bias might affect the results.

In addition, the model uses national averages that include significant manufacturing customers, which are "more likely to incur costs than non-manufacturing industry customers."[51] DEP reported a significantly lower share of its C&I customers as manufacturing than the ICE Calculator default values (the LBNL Report interruption costs are based on manufacturing making up 23% of Medium and Large C&I customers; for DEP, that number is 4.4%). Thus, high interruption cost estimates for C&I customers in the

[51] LBNL Report, at 28, Thomas Exhibit 1.

LBNL Report may be influenced by the costs reported by manufacturing customers in other areas of the country.

Q. WHICH UTILITIES PROVIDED INTERRUPTION COST SURVEY DATA TO LBNL FOR PURPOSES OF THIS STUDY?

A. The LBNL Report does not provide details on individual utilities that conducted each study, but classifies them into regions. The LBNL Report includes 34 different datasets, from 15 interruption cost surveys, fielded by 10 different utility companies between 1989 and 2012.[52] Of the 10 utility companies, three were from the southeast, one was from the Midwest, and five were from the southwest, west, or northwest. No studies from the mid-Atlantic or northeast were included, which the authors flag as a limitation of the study.

Q. DID DEP PROVIDE ANY INTERRUPTION COST DATA TO THE LBNL STUDY?

A. Interestingly, the 2009 LBNL Report lists some utilities that provided interruption cost surveys, which includes Duke Energy (the jurisdiction is not mentioned) and Cinergy (now Duke Energy Ohio).[53] Based upon discovery requests in this proceeding, the Public Staff has confirmed that DEC provided data in 1997 as Duke Energy, prior to the Cinergy and

[52] *Id.* at 16.

[53] Other contribution electric utilities include Bonneville Power Administration, Mid America Power, Pacific Gas and Electric Company, Puget Sound Energy, Salt River Project, Southern California Edison, and Southern Company. *See* 2009 LBNL Report at i.

Progress mergers; this data would be listed as Midwest-1 or Midwest-2. The Company does not have access to the data that was provided to LBNL, and in any case, DEP did not provide any data to the study. The Company stated that due to the existence of the ICE Calculator and the LBNL Reports, it does not see value in conducting its own interruption cost study. It should be noted that of all the individual observations in the dataset, approximately 33% come from the southeastern utility studies (although southeastern is not explicitly defined in the LBNL Report).[54]

Q. REGARDING THE CUSTOMER COSTS IN THE LBNL REPORT DATASET, DO YOU HAVE CONCERNS REGARDING THE NATURE OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS?

A. Yes. As I have stated before, these customer reliability benefits are based on estimated economic losses, and are impossible for the Company to validate. Some of the interruption cost surveys that underpin the LBNL Report are from WTP or WTA surveys. While there has been significant work over the years to improve WTP survey design, particularly in the marketing sector, one challenge is the so-called "hypothetical bias."[55] This bias refers to the difference between the survey respondent's answer and what they would actually pay in a real-life scenario. The authors of the 2009

[54] Based on an analysis of Table 1-1 in the LBNL Report, at 16.

[55] There is significant controversy in the literature about the validity of the various WTP survey methods, and the relationship between WTP and WTA surveys. *See* the 2009 LBNL Report, at xviii, fn 3. Several academic papers are cited.

LBNL report refer to this: “[we] cannot determine, prima facie, the biases inherent in such self-reports of cost estimates associated with hypothetical interruption scenarios.”[56]

The 2009 LBNL Report states that all of the C&I interruption cost estimates were based upon direct cost estimation surveys, and all residential interruption cost estimates used in their meta-analysis were based upon WTP surveys.[57] It is impossible to gauge the extent or direction of the potential hypothetical bias in the LBNL Report’s data. It is also impossible to know how C&I customers with backup generation factored this into their interruption cost estimates. While the use of direct cost estimation surveys for C&I customers may reduce the hypothetical bias, it is unclear to what extent. I appreciate that these types of surveys have been used for decades to evaluate much more than electric reliability, and significant research has been done into improving the accuracy of the response for intangible goods through clever questionnaire design. However, the fact remains that the actual reliability benefits customers realize are not likely to match those used in the GIP CBAs.

[56] 2009 LBNL Report, at 6, Thomas Exhibit 6.

[57] *Id*. at 8. Some residential surveys include direct cost estimation or WTA surveys, but these were excluded from the meta-analysis.

Q. HOW ARE CUSTOMER RELIABILITY BENEFITS ALLOCATED AMONG CUSTOMER CLASSES?

A. North Carolina customer reliability benefits are heavily skewed towards C&I customers. In all CBAs but for the Transmission H&R Line Projects,[58] customer reliability benefits are broken out by Residential, Small C&I, and Medium and Large C&I. For the $6 billion in reliability benefits in DEP and DEC, that are assigned by class, $163 million (2.7%) accrue to Residential, $2.7 billion (43.8%) accrue to Small C&I, and $3.3 billion (53.5%) accrue to Medium and Large C&I. Reliability benefits for the two C&I classes alone comprise 64% of all GIP benefits, customer and operational.

Q. WHAT AMOUNT OF RELIABILITY BENEFITS WERE NOT ASSIGNED TO CUSTOMER CLASSES?

A. Approximately $2 billion in reliability benefits from Transmission H&R Line Projects were not assigned to customer classes because customers are generally supplied from multiple circuits, and therefore transmission benefits are difficult to assign directly to any customer class.[59] The Company has indicated that these benefits are assigned using a customer-weighted jurisdictional cost per outage; it can therefore be assumed that

[58] The reliability benefits for Transmission H&R Line Projects are broken into three categories depending on their source, as opposed to their beneficiary. These sources of transmission reliability benefits are: structure replacement, static line replacement, and conductor replacement. While it is reasonable that these benefits would be allocated among customer classes in a similar manner as other reliability benefits, I do not make that assumption for my calculations here.

[59] *See* Docket No. E-7, Sub 1214, Oliver Rebuttal testimony, at 26.

these benefits accrue in a similar manner as other customer reliability benefits (i.e., significantly skewed towards C&I customers).

Q. IS THE MAGNITUDE OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS REALISTIC?

A. At first glance, the amount of reliability benefits claimed strains credulity. The Company provided data indicating that the GIP proposal will result in incremental improvements to SAIDI and SAIFI of approximately 33% and 26%, respectively.[60] DEP and DEC estimate $8 billion in reliability benefits across their North Carolina system, consisting of nearly $6 billion in C&I benefits, resulting from these improvements. The C&I benefits alone, if accurate, represents approximately 1% of North Carolina's 2018 gross domestic product.[61] For context, from 2014 to 2019, DEP saw SAIDI and SAIFI worsen by 20% and 7%, respectively. No evidence has been presented that this has had an impact on the North Carolina economy.

Q. DOES THE ALLOCATION OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS RAISE ANY CONCERNS?

A. The allocation of GIP reliability benefits raises serious questions about equity in cost allocation and rate design. Claimed customer reliability

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[60] Measured relative to DEP's 2019 North Carolina service quality. SAIDI was 149.1 minutes per customer and SAIFI was 1.2937 interruptions per customer.

[61] Department of Commerce, North Carolina Annual Economic Report: A Year in Review, 2018. *Available at* https://www.nccommerce.com/blog/2019/11/04/nc-annual-economic-report-gross-domestic-product.

benefits for C&I customers are estimated at approximately $6 billion, representing over 97% of customer reliability benefits broken out by class, 73% of total customer reliability benefits,[62] and 64% of <u>all</u> GIP program benefits. Residential reliability benefits only comprise 1.8% of all GIP program benefits. While it can be assumed that all customers benefit equally from the other benefit categories (particularly operational benefits), customer reliability benefits comprise the vast majority of all claimed benefits and their allocation has an enormous impact on the allocation of total GIP benefits.

In addition, certain programs, such as SOG, have the potential to provide significant reliability benefits, but only to those selected circuits on which it is deployed (with the exception that Company resources have the potential to be more efficiently deployed on non-SOG circuits as a result of SOG); nevertheless, costs will be recovered from all ratepayers. This was a concern identified by the Commission when it rejected the Company's proposed Grid Reliability and Resiliency Rider.[63]

[62] This includes the approximately $2 billion in customer reliability benefits that the Company has not assigned to specific customer classes.

[63] *See* the Commission's *Order Accepting Stipulation, Deciding Contested Issues, And Requiring Revenue Reduction* in Docket No. E-7 Sub 1146, at 147.

Q. HOW DOES THE ALLOCATION OF RELIABILITY BENEFITS COMPARE TO HOW GIP COSTS WILL BE ALLOCATED?

A. If there is no new allocation factor proposed for GIP investments, all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for Transmission and Distribution (T&D) expenditures. Figure 5 below presents the allocation of customer reliability benefits next to the traditional cost allocation of T&D investments from DEP's per books Cost of Service Study (COSS). Public Staff witness McLawhorn discusses COSS methodologies in his direct testimony.

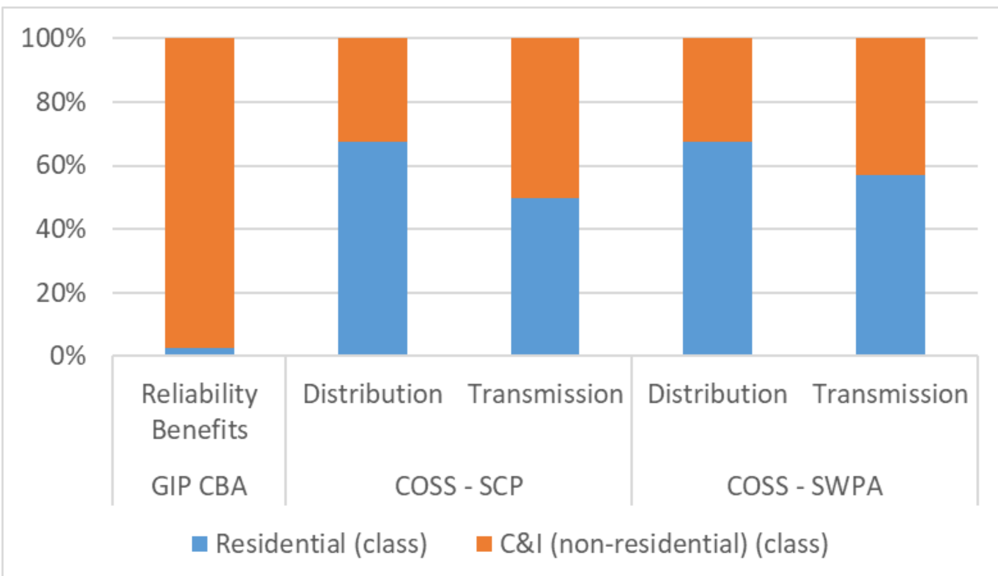

Figure 5: Allocation of assigned customer reliability benefits and T&D class factors for per books cost allocation.

Distribution investments are typically allocated using a non-coincident peak allocation factor; for residential customers, the class factor is approximately

68%.[64] Transmission investments are allocated on a transmission demand allocation factor; for residential customers, the class factor is approximately 50%.[65]

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE ALLOCATION OF GIP COSTS?

A. At this time, I am not recommending that GIP costs be allocated differently than traditional T&D investments. However, I do believe the issue is ripe for Commission consideration, particularly in light of the Commission's June 14, 2019 *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100 Sub 101, which requires the Company to "file testimony in [its] next general rate case applications regarding the benefits that distributed generators are receiving from the Utility's System, estimating their share of related costs, and providing options for recovering those costs from distributed generators." If the Commission agrees that this issue merits further study, DEP's and DEC's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits.

[64] This number reflects the primary distribution allocation factor found in DEP's per books Cost of Service Study (*see* E-1 Item 45a).

[65] This number reflects the transmission demand allocation factor found in DEP's per books Cost of Service Study (*see* E-1 Item 45a). Public Staff witness McLawhorn has proposed utilizing a different cost allocation methodology (SWPA); the corresponding residential retail transmission allocation factor is 56.8%.

D. Other Customer Benefits

Q. STEPPING BACK FROM THE LBNL REPORT, CAN YOU SPEAK TO THE OTHER CATEGORIES OF CUSTOMER BENEFITS THAT THE COMPANY HAS QUANTIFIED?

A. Yes. The other two categories are CO_2 emission reductions and DER Enablement. The former is included in programs which lead to reduced overall generation and thus lower CO_2 emissions, including IVVC, DSDR, and SOG (only in DEC). The DER Enablement benefit attempts to capture the value of increased capacity for distribution-connected solar photovoltaic (PV) resources as a result of SOG – while DER may encompass many technologies, the Company only considered added PV. Essentially, increased capacity and connectivity of selected circuits through SOG lead to an assumed higher DER limit than the baseline. This assumed higher deployment of DER leads to a reduction in energy costs and associated emissions costs, totaling $34 million in DEP and $53 million in DEC.

Q. DO YOU HAVE ANY CONCERNS WITH THESE TWO BENEFIT CATEGORIES?

A. Yes. Regarding avoided CO_2 benefits, the Public Staff recognizes that some stakeholders in North Carolina do place a value on reduced carbon emissions, and the Public Staff supports the Company's use of projected carbon pricing in its IRP. However, it is important to note that CO_2 emissions currently do not have an actual cost to the utility, and DEP does not include

CO_2 prices when it calculates its avoided energy rates for the purpose of paying PURPA contracts. As such, the Public Staff believes the CO_2 benefits should be removed from the GIP CBAs. The CO_2 emission reduction benefits are relatively minor ($135 million, or 1.5% of total GIP program benefits), and the effects of removing them from the three programs which include them are shown below in Table 4.

Table 3: Effect of removing CO2 emission reduction benefits from select GIP CBAs

Program (NC only)	Total Benefits ($M)	CO_2 Benefits ($M)	BCR w/ CO_2	BCR w/o CO_2
IVVC (DEC)	$ 546	$ 86.0	1.2	1.0
DSDR (DEP)	$ 232	$ 49.7	35.3	27.8
SOG (DEC only)	$ 2,088	$ 0.056	2.7	2.7
Total	**$ 2,868**	**$ 135.8**		

The DER Enablement benefits rely upon assumed limits to DER penetration on distribution circuits, with and without SOG. Underlying these assumptions is the additional assumption that customers on SOG circuits will seek to interconnect DER beyond the baseline limit; this benefit can only be realized if the actual DER deployed on a SOG circuit exceeds the capacity limits assumed by the Company. DEP assumes that current SOG circuits are limited at 496 MW of potential DER interconnections, and that this limit will be reached on SOG circuits by 2027. While I am not at this time questioning the Company's DER forecasting methods, I will point out that as of 2019, DEP has connected less than 50 MW of distribution-connected DER on its entire system.[66] This benefit, therefore, is contingent on significant growth in the DER market in DEP's service territory. With the provision in House Bill 589 to revise the existing net metering tariff,[67] that level of growth in distribution connected DER is questionable and I am not convinced this benefit will truly bring value to ratepayers.

E. Operational Benefits

Q. LET'S TURN NOW TO THE OPERATIONAL BENEFITS THAT THE COMPANY HAS QUANTIFIED. CAN YOU DESCRIBE THEIR SOURCES AND MAGNITUDE?

A. Total operational benefits from all GIP CBAs are estimated at $942 million, summarized in Figure 6 below (all figures are NPV over the program life, for DEP and DEC, North Carolina only). The majority of these benefits (59%) fall into the fuel and related category, benefits which largely are derived from lower overall electricity consumption due to lower distribution circuit voltages enabled by IVVC, DSDR, and SOG. A related benefit is avoided capacity, comprising approximately 12% of total operational benefits, which

[66] This number includes all net metered projects of less than 1 MW, compiled from quarterly performance reports in Docket No. E-100, Sub 101A.

[67] North Carolina Session Law 2017-192 (known as HB 589) revised N.C. Gen. Stat. § 62-126.4 to require utilities to file new net metering tariffs and allowing customers to continue under the net metering tariff in effect at the time of interconnection until January 1, 2027.

reflects the reduced need for future capacity due to IVVC and SOG, both of which enable emergency voltage reductions in peak periods. All of the avoided capacity benefit is claimed by DEC; DEP does not include avoided capacity benefits in any CBAs. I discuss the reason for this later in my testimony.

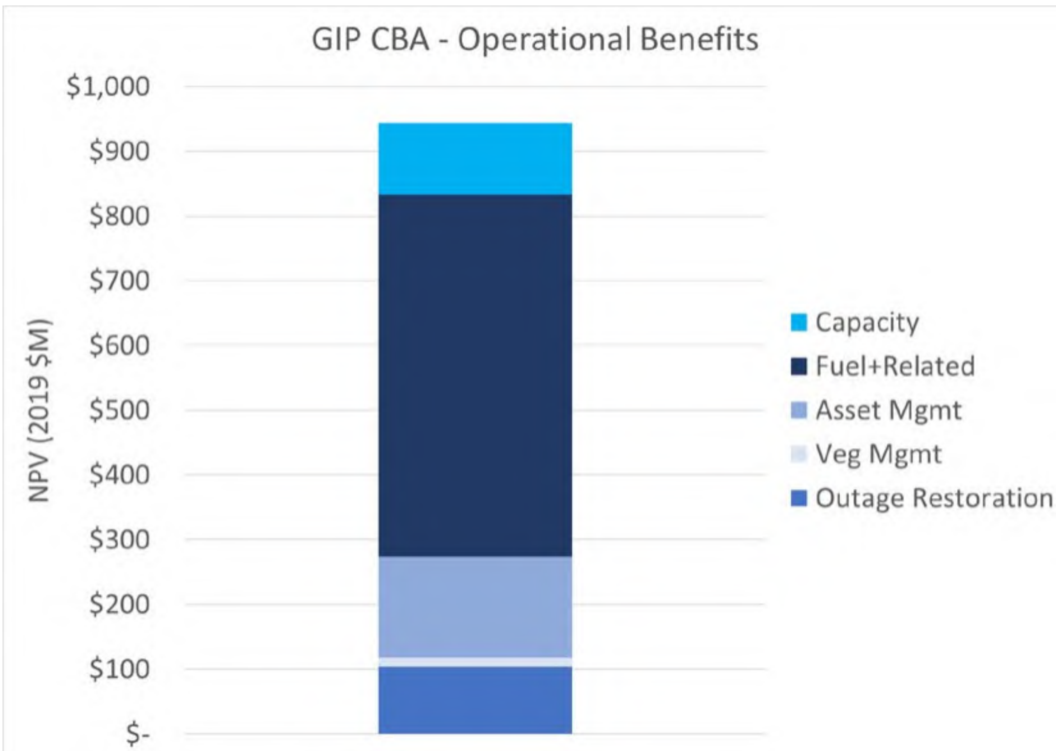

Figure 6: Operational Benefits from GIP CBAs (DEC and DEP, NC Only)

The next largest benefit category is the asset management (AM) benefit. This benefit reflects avoided future asset replacement or repair costs due to accelerated replacement or hardening planned by certain GIP programs, primarily Transmission H&R, Transmission Transformer Bank Replacements, T&D Oil Breaker replacements, and TUG. This benefit is estimated at $156 million, comprising 17% of total operational benefits.

The reduction in outage restoration costs is an ancillary benefit to the reduction in outages projected from GIP; at $103 million, it comprises 11% of total operational benefits. The only programs that included this benefit are TUG and DTR, as other programs that increase reliability (SOG, T&D Oil Breaker Replacement, Transformer Bank Replacements) do not necessarily reduce the number of times the Company must dispatch a repair crew. These estimates are based upon historical costs of outage repairs divided by the number of outages requiring repair crews.

Finally, the TUG CBA includes a reduction in vegetation management costs of $13 million, reflecting the reduced need to trim vegetation where distribution lines have been buried. This is a minor benefit, comprising only 1% of total GIP operational benefits and less than 1% of total TUG benefits.

Q. IF REALIZED, WOULD THESE BENEFITS BE LIKELY TO CAUSE LOWER RATES FOR RATEPAYERS?

A. Generally, yes. With the exception of avoided capacity and possibly the AM benefit, all of these benefit categories directly reflect reductions in operating expenses or rate base because of GIP programs. Avoided capacity has been quantified similarly to the method that is used for setting the avoided capacity rate for small power producers selling their output to the Company under avoided cost rates pursuant to N.C. Gen Stat § 62-156; as such, it reflects the programs' contribution to reducing the need for future capacity additions.

Q. DO YOU HAVE ANY CONCERNS WITH THE OPERATIONAL BENEFITS?

A. Yes. I have concerns regarding the claimed avoided capacity and asset management benefits. However, DEP does not include avoided capacity in any of its CBAs, with the entirety of this benefit claimed in DEC's territory in the IVVC and SOG CBAs. I disagree with how this benefit was calculated in DEC,[68] but this does not apply to any DEP programs.

Q. WHY DID DEP NOT INCLUDE ANY AVOIDED CAPACITY BENEFITS?

A. DEP did not include avoided capacity benefits due to underlying differences in the IVVC and SOG program in DEP. First, IVVC in DEP is not a new program, but rather a conversion of the existing DSDR peak-shaving program (which is an operational mode of IVVC) into a CVR energy-reduction program. Thus, the IVVC program in DEP does not provide any new avoided capacity benefits; in fact, converting from DSDR to CVR operational mode will <u>reduce</u> the ability of the DEP system to peak-shave, thus imposing avoided capacity <u>costs</u> (i.e., a negative benefit). DEP recognizes this fact, indicating that they will need to seek "relief from the current DSDR peak shaving obligation."[69] However, DEP has not yet estimated the amount of peak reduction lost by this conversion, and

[68] I addressed DEC's inappropriate calculation of avoided capacity benefits in my direct testimony in Docket No. E-7, Sub 1214, at 57-62.

[69] *See* DEP response to PS DR 54-14, attached as Thomas Exhibit 7.

therefore the CBA does not represent an accurate estimate of the benefits to ratepayers.[70]

The DEC SOG program includes investments in "circuit conditioning," which are activities such as reconductoring power lines, balancing load, and installing distribution line capacitors and voltage regulators. However, DEP has already completed circuit conditioning as a component of its DSDR deployment. Thus, the SOG program in DEP does not include the costs of circuit conditioning, and no corresponding additional avoided capacity benefit is realized in DEP.

Q. IN LIGHT OF THE UNCERTAINTY REGARDING THE NET BENEFITS OF THE DSDR CONVERSION, DO YOU MAKE ANY RECOMMENDATIONS?

A. Yes. DEP has indicated a willingness to test the rollout of the DSDR to CVR Conversion in order to validate the benefits and determine the amount of lost peak-shaving benefits,[71] particularly in light of DEP's reliance on DSDR to provide over 200 MW of winter Demand Side Managemnet (DSM) in its 2019 IRP. I recommend that DEP reduce the scope of the DSDR to CVR Conversion project and identify the minimum amount of investment required

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[70] *Id*. Regarding the DSDR conversion to CVR, DEP states: "However, the lost benefits (including the initial deferral of peaking units), due to the reduction of peak shaving capability have yet to be calculated. To make an informed decision, further analysis will be required to accurately quantify the impacts on DSDR. When the DMS upgrade is complete, Duke Energy will be able to conduct additional testing and a more thorough analysis of the peak shaving capability impact."

[71] *See* DEP response to PS DR 132-7, attached as Thomas Exhibit 8.

to determine that the conversion is a net benefit to ratepayers. In light of the Commission's position that "additional emphasis should be placed on defining and implementing cost-effective DSM programs that will be available to respond to winter peak demands,"[72] DEP should proceed in a manner that will ensure that the decision to reduce peak shaving capabilities, particularly in the winter, does not cost ratepayers more than anticipated.

Q. MOVING ON TO YOUR OTHER CONCERN, HOW IS THE ASSET MANAGEMENT BENEFIT CALCULATED?

A. In the Transformer Bank Replacement and Oil Breaker Replacement programs, the assets that are being replaced in these programs often have many years of remaining life when they are replaced as part of GIP, summarized in Table 5 below. For example, in the Transformer Bank Replacement program, DEP assumes that transmission transformers replaced as part of this program have an average of 14 years of life remaining. Because the discount rate used is higher than the escalation rate, DEP estimates that 59% of the capital cost to replace a transmission transformer today is offset by the avoided cost of replacing that asset in 14 years, in NPV terms. Another way of looking at this is that it costs ratepayers <u>70% more</u> to replace a transmission transformer today than if DEP waited

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[72] *See Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans,* Docket No. E-100, Sub 147, at 26 (June 27, 2017).

until the end of the asset's life. In other contexts, DEP has recognized the value to ratepayers of delaying capital investments.[73]

Table 4: Average Remaining Life (in years) of transformers and oil breakers usd in GIP CBAs.[74]

Asset	Remaining Life (Years)		AM as % of Capital Cost	Cost Increase due to Early Replacement[75]
	DEP	DEC		
Distribution Transformers	8	6	75%	33%
Transmission Transformers	14	12	59%	70%
Distribution Oil Breakers	5	5	81%	23%
Transmission Oil Breakers	10	10	66%	51%

Q. DO YOU BELIEVE THAT THESE TWO CBAs SHOULD BE REVISED TO REDUCE OR REMOVE THE ASSET MANAGEMENT BENEFIT?

A. Not at this time. Other jurisdictions have raised concerns about this benefit category,[76] which some believe requires "ratepayers to pay today for

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[73] *See* Docket No. E-2, Sub 1185, Application for a CPCN to Contruct a Microgrid Solar and Battery Storage Facility in Madison County, North Carolina, Direct Testimony of Jonathan A. Landy, at 7-8, and the Supplemental Testimony of Jonathan A. Landy, at 6. The costs of delaying the distribution line upgrade were included in the confidential cost-benefit analysis supporting the Hot Springs microgrid.

[74] The asset life of transformers is considered to be 40 years (DEP response to PS DR 54-4).

[75] Cost Increase due to Early Retirement is calculated by comparing the cost to replace the asset now with the discounted cost of replacing it at the end of its useful life.

[76] Virginia Commission Staff testified that the analogous benefit claimed by VEPCo should be removed. *See* VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 18-19.

something they could have been spared until some future test failure."[77] As I have shown, the AM benefit quantified by the Company merely offsets a portion of the capital costs to replace the asset early; therefore, the CBAs properly recognize early replacement as a net cost in the Transformer Bank Replacement and Oil Breaker Replacement programs. Thus, for these two programs, I would not recommend that the AM benefit be removed from the CBA.

Q. WHAT ABOUT THE OTHER PROGRAMS THAT CLAIM THIS ASSET MANAGEMENT BENEFIT?

A. For the TUG program, the AM benefits reflect two categories: the avoided need to replace deteriorated overhead conductors and the avoided need to replace deteriorated poles. While these benefits are real, the CBA does not include an offsetting cost to replace deteriorated or damaged underground conductors beyond an assumed annual O&M expense of 3% of the project capital cost. As underground lines can still be damaged from flooding and improper digging, which typically require more costly repairs than overhead lines, it is likely the AM benefits of TUG are overstated.

The Transmission H&R Flooded Substation programs (both reinforce and relocate) estimate their AM benefits by assuming that without these

[77] *See* the Direct Testimony of Dennis Stephens in Docket No. E-7, Sub 1214, at 36.

programs, the existing substations will need to be rebuilt every six years.[78] While these benefit estimates are not necessarily unreasonable, I highlight the fact that the average cost to repair a substation varies widely depending on the severity and path of the storm. As seen in Figure 7, depending on the storm, some substations may not even incur repair costs, and the high cost associated with repairing the Wallace 230kV substation after hurricane Florence is an outlier. The costs associated with the Wallace 230kV rebuild alone increases the AM benefit of the entire substation reinforce program by over $6 million, or 28%. In addition, DEP is already deploying flood mitigation measures as part of its normal storm preparation activities. For instance, seven substations were outfitted with temporary dams in preparation for hurricane Dorian.[79]

[78] This is based upon three events in 18 years (Hurricanes Floyd in 1999, Matthew in 2016, and Florence in 2018).

[79] *See* Direct Testimony of Rufus S. Jackson, at 29.

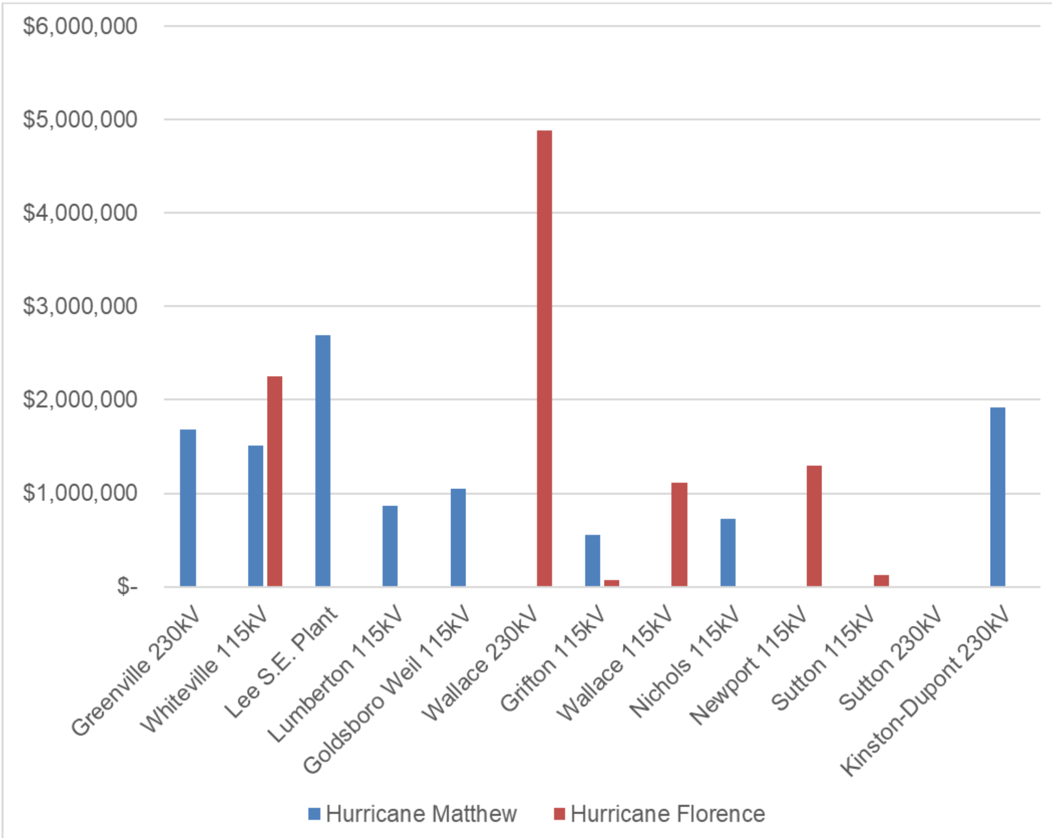

Figure 7: Substation rebuild costs after hurricanes Matthew and Florence.[80]

Source: Oliver Exhbit 7, Flooded Substation Reinforce CBA

Q. DID YOU TAKE ISSUE WITH THE ASSET MANAGEMENT BENEFIT AS CALCULATED BY DEC IN ITS GENERAL RATE CASE, DOCKET E-7, SUB 1214?

A. No. My testimony in DEC's ongoing general rate case largely accepted this benefit as reasonable.[81] However, after reviewing the testimony of North Carolina Justice Center, et. al. witnesses Stephens and Alvarez, and

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[80] The Whiteville 115kV costs were excluded from the calculation of the AM Benefit in the Reinforce CBA.

[81] *See* Direct Testimony of Thomas in Docket No. E-7, Sub 1214, at 55-56.

reviewing how deferred investments were treated in DEP's Hot Springs microgrid CPCN application, I have reconsidered my position.

Q. DO YOU MAKE ANY RECOMMENDATIONS REGARDING THIS BENEFIT?

A. Yes. I recommend that the Transformer Bank Replacement and Oil Breaker Replacement programs be carefully deployed, or even scaled down, as DEP improves its ability to monitor the health and performance of its assets in the field. As I have summarized in Table 5, ratepayers face significant cost increases associated with the early replacement of these assets. In addition, the Company has proposed other GIP programs to monitor the health of its grid assets in order to more efficiently replace assets near failure, such as Transmission System Intelligence and Enterprise Applications Health Risk Management (HRM) tool.[82] Simply replacing transformers and oil circuit breakers proactively, without regard to the remaining life of the asset, would appear to increase costs and reduce the benefit of these advanced tools.

I also recommend that DEP revise its TUG CBA to include the costs of unanticipated faults on underground lines through the life of the CBA.

[82] These two programs are discussed in more detail in the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson and in Oliver Exhibit 10, at 41, 81.

III. GIP Program Costs

Q. WHAT COSTS ARE CONSIDERED IN THE GIP CBAs?

A. The CBAs include capital costs and operations and maintenance (O&M) costs for certain projects. Capital costs describe electronic devices, equipment, hardware, and software systems that would generally be included in the Company's rate base. For devices that have an assumed life of less than the CBA evaluation period, replacement costs are included in future years. O&M costs are those costs associated with maintaining the equipment or systems that have been deployed, and would be booked as expenses by the Company.

As illustrated in Figure 1, the vast majority (96%) of costs in the GIP CBAs are capital (which includes labor), with the remaining 4% consisting of O&M. Note that the DSDR Conversion in DEP does not include asset costs, but rather capitalized labor costs, associated with reprogramming existing assets. Table 6 below summarizes the costs included in the individual GIP CBAs, along with reasons why certain programs had O&M costs excluded. When O&M costs are not expected to change as a result of a GIP program, these costs are excluded from the comparative analysis.

Q. DO YOU HAVE ANY CONCERNS REGARDING HOW THE COMPANY IS REPORTING THE ESTIMATED COSTS OF GIP?

A. Yes. For one, it appears that depending on where one looks, GIP costs change. For example, the sum of the estimated capital costs of all CBAs

(DEC and DEP) is approximately $1.90 billion budgeted to NC.[83] However, if you look at the capital costs for those same programs presented in Oliver Exhibit 10, the total is $1.78 billion budgeted to NC. In addition, through discovery it has come to light that some project costs within individual CBAs were excluded because those costs were spent prior to 2019. It is difficult to ascertain how widespread this issue is across all of the CBAs filed in this case, but excluding some costs while including all benefits will tend to improve the project's BCR.

[83] *See* Oliver Exhibit 7.

Table 5: Cost categories included in the GIP CBAs. "Yes" indicates this cost is quantified in the GIP CBA.

GIP Program	Capital Costs	O&M Costs
Self-Optimizing Grid	Yes	Yes
Integrated Volt/VAR Control	Yes	Yes
DSDR	Yes (Labor Only)	Yes
T-Transformer Bank Replacement	Yes	No – no change in O&M expected due to accelerated replacements
Distribution Transformer Retrofit	Yes	Yes
Transmission H&R	Yes	No – O&M costs assumed to be the same before and after project
Oil Breaker Replacements	Yes	No – O&M costs assumed to be similar for oil breakers and gas / vacuum breakers
Transmission Line Projects (DEC)	Yes	No – O&M costs assumed to be the same before and after project
Transmission Line Projects (DEP)	Yes	No – O&M costs assumed to be the same before and after project
LDI / HIS	Yes	No – O&M costs assumed to be the same before and after project
Targeted Undergrounding	Yes	Yes

Q. HOW DOES THE COMPANY ESTIMATE CAPITAL COSTS?

A. The methodology for estimating capital and O&M costs vary by CBA; some cost estimates are likely to be more accurate than others. As described in the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson, some of the GIP programs consist of accelerated deployments of programs already underway. For example, DEP and DEC are both already proactively[84] replacing oil circuit breakers with gas and vacuum circuit breakers at an average of 70-100 replacements each per year. The T&D Oil Breaker Replacement program proposed in GIP would enable DEP and DEC to each proactively replace 120-160 circuit breakers per year.[85] This is true for several other GIP programs, including Transformer Bank Replacements, DTR, TUG, and Transmission H&R. For these CBAs, the cost estimates are expected to be relatively accurate, as the Company utilizes actual cost data from historical projects in its jurisdiction.

Q. HOW DOES THE COMPANY ESTIMATE CAPITAL COSTS FOR NEW PROGRAMS?

A. For new programs that are not currently being deployed, such as SOG, IVVC, and the DSDR conversion in DEP, the Company has indicated it uses cost estimate methodologies defined by the American Association of Cost Engineering (AACE), which recommends practices for estimating engineering, procurement, and construction processes. Depending on

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[84] A proactive replacement is a replacement completed before the unit in the field fails, avoiding the outages associated with an unexpected failure.

[85] The CBA for the Oil Breaker Replacement program anticipates an average of 114 breakers replaced per year in DEP; thus, the CBA appears to analyze the entire program, not the incremental acceleration proposed in GIP.

factors such as the development stage of the project, the purpose of the estimate, and the estimating methodology used, AACE defines five estimate classes from Class 1 (most accurate) to Class 5 (least accurate).[86]

SOG capital costs include four components: (1) switch automation and circuit segmentation, (2) circuit capacity and connectivity, (3) substation bank capacity, and (4) control devices and advanced distribution management systems. DEP has indicated that the SOG CBA costs are Class 4 and were generated without cost estimators visiting actual sites for SOG deployment. Capital costs were calculated by first generating a high-level estimate of the number of devices to be deployed and the number of circuit miles to be upgraded at the circuit level; per-unit costs based on a combination of historical costs (i.e., for upgrading circuit capacity) and known or quoted (i.e., for automated switches) were then applied to those estimates. The AACE standard states that the expected accuracy range of a Class 4 estimate is -15% to -30% on the low side, and +20% to +50% on the high side. These costs are expected to change as engineers visit the field and project scope is refined.

The DSDR conversion capital costs are broken into several broad categories, including transmission, telecom, information technology,

[86] A sample copy of AACE International standard “18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries” was shared with the Public Staff as part of discovery.

distribution, and staff support. DEP states that these are Class 4 estimates, supported by an evaluation of materials, labor, overhead, and contingencies. DEP states that there will be zero new physical grid assets as a result of the DSDR Conversion, so capital costs are labor costs only.

Q. ARE YOU AWARE OF ANY CHANGES TO CAPITAL COST ESTIMATES SINCE THE COMPANY FILED ITS APPLICATION?

A. No. To the Public Staff's knowledge, DEP has not performed any updated cost estimates for any GIP programs since October 30, 2019.

Q. YOU MENTIONED EARLIER THAT THE COMPANY DID NOT PROVIDE ANY SENSITIVITY ANALYSES. HAS THE PUBLIC STAFF PERFORMED SUCH AN ANALYSIS OF CAPITAL COSTS ON ANY GIP CBAs?

A. Yes. Presented below are capital cost sensitivities for the two most capital intensive GIP programs, SOG and Distribution Transformer Retrofit (DTR). Table 7 summarizes a sensitivity analysis of the SOG program (DEP only), showing that the program retains a net benefit even if capital costs double from initial estimates (refer to the "Benefits as Filed" columns). However, to demonstrate how sensitivity analyses must consider multiple assumptions, I also show the same capital cost sensitivity results for SOG if momentary outages are accounted for, as I have discussed previously in my testimony. It that situation, capital cost increases can quickly eliminate net benefits to ratepayers (refer to the "Momentary Outages Accounted For" columns).

Table 6: Sensitivity Analysis of SOG (DEP-NC).

Capital Cost Variance	**Benefits As Filed**		**Momentary Outages Accounted For**	
	BCR	**Capital Cost NPV ($M)**	**BCR**	**Net Benefits NPV ($M)**
-50%	6.0	$ 154.4	3.1	$ 329.0
-30%	4.3	$ 216.2	2.2	$ 267.2
0% (Baseline)	**3.1**	**$ 308.8**	**1.6**	**$ 174.6**
50%	2.0	$ 463.3	1.0	$ 20.2
100%	1.5	$ 617.7	0.8	$ (134.2)

The CBA for the DTR program is also influenced by capital cost increases. Table 8 below shows the same capital cost sensitivities as were performed for SOG for two scenarios: as originally filed, and with long-duration outage costs capped at the cost of a 16-hour outage from the LBNL Report. I show the impact on total capital costs based on the sensitivity analysis, and I also show the impact on net benefits when the long-duration outages are capped. A capital cost increase of 50% associated with the DTR program would still yield a cost-effective program, unless long-duration outages are capped, at which point the program BCR falls below 1.0.

Table 7: Sensitivity Analysis of capital costs with benefits as filed and with long-duration outages capped at 16 hours (DEP and DEC in NC).

Capital Cost Variance	Benefits As Filed		Long-Duration Outages Capped at 16 Hours	
	BCR	**Capital Cost NPV ($M)**	**BCR**	**Net Benefits NPV ($M)**
-50%	2.9	$ 84.5	2.7	$ 143.6
-30%	2.1	$ 118.4	1.9	$ 111.0
0% (Baseline)	**1.5**	$ 169.1	**1.4**	$ 62.1
50%	1.0	$ 253.6	0.9	$ (19.4)
100%	0.8	$ 338.2	0.7	$ (100.9)

Q. ARE THERE ANY COSTS FROM GIP THAT MAY NOT BE INCLUDED IN THESE ANALYSES?

A. Possibly. One area that was not considered in the GIP CBAs was the potential impact on materials and supplies (M&S) inventory and the associated carrying costs. To illustrate how a GIP program may impact M&S inventory, consider the Oil Breaker Replacement program. If gas and vacuum circuit breakers are more expensive to carry on the Company's books than oil circuit breakers, holding the same number of spare circuit breakers will increase M&S inventory, assuming similar reliability and lifetime characteristics.[87] This could impact customer rates and the cost-effectiveness of certain CBA programs. However, I have not quantified this potential impact and expect that it is relatively minor compared to the costs of the entire GIP proposal.

IV. Findings Related to GIP Cost Recovery

Q. IS DEP REQUESTING RECOVERY OF GIP-RELATED COSTS IN THIS PROCEEDING?

A. Yes. As discussed in the testimony of Public Staff witnesses David Williamson and Tommy Williamson, DEP has placed approximately $242 million of GIP projects in service since its last general rate case, with an additional $8.0 million in O&M costs over the same time period. The primary drivers are investments in Advanced Distribution Management System (ADMS) at $45 million, SOG at $41 million, DTR at $30 million, Enterprise Communications at $26 million, and physical and cyber security at $20 million.

[87] The Company, in its CBAs, assumed that gas and vacuum breakers have similar lifetimes and failure rates as oil breakers.

Q. HAS THE PUBLIC STAFF REVIEWED THESE COSTS?

A. Yes. We have requested detailed work breakdown structures for dozens of individual T&D projects and reviewed the costs of the GIP-specific projects within the projects closed to plant.

Q. PLEASE SUMMARIZE THE RESULT OF YOUR REVIEW OF GIP-RELATED COSTS CURRENTLY IN RATE BASE.

A. Overall, my review has raised significant concerns, which I summarize in three main areas: (1) how the Company is tracking its costs related to GIP and whether these costs are actually GIP related; (2) how the Company is budgeting for projects that consist of multiple GIP elements; and (3) whether GIP cost estimates are valid in light of actual projects executed.

Q. PLEASE DESCRIBE HOW THE COMPANY IS TRACKING GIP COSTS.

A. In its response to PS DR 76-3, DEP provided system level assets placed in service and O&M expenses associated with each GIP program, and these costs appear to be assigned to certain internal accounts with project IDs being labeled as GIP-related. When these projects are closed to plant, however, they are placed in normal T&D related FERC accounts. There is some concern that the number of these relatively smaller GIP projects will be difficult to review in the future, particularly if the projects fall below the Company's threshold for certain project management tools, such as build gates and variance reports.

Q. HOW DOES THE COMPANY TREAT PROJECTS THAT HAVE ASPECTS OF MULTIPLE GIP PROGRAMS?

It is not entirely clear; I found several projects that were labeled as related to a certain GIP program that were later found to coincide with multiple programs. For example, a $2.5 million Transmission Circuit Breaker Replacement project replaced six oil circuit breakers at a cost of $420k per breaker; this is far greater than the $192k per breaker estimate in the CBA. DEP stated that this is because the project was a “bundled project,” which included scope from the Transmission System Intelligence program (no cost breakdown between the two programs was provided to the Public Staff). I am concerned that tracking the actual costs of GIP programs in the future will be difficult, if not impossible, when the Company combines projects in this way.

Q. DO ANY PROGRAMS IN PARTICULAR CONCERN YOU?

A. Yes. I have some concerns that the Transmission System Intelligence program may become – if it has not already – a “catch all” for a wide variety of routine transmission investments. The Company describes TSI as covering four main areas: (1) the replacement of electromechanical relays with remotely operated digital relays; (2) the implementation of intelligence and monitoring technology capable of providing asset health data and driving predictive maintenance programs; (3) the deployment of remote monitoring and control functionality for substation and transmission line devices, which supports rapid service restoration; and (4) resiliency projects to rapidly respond to system outages or disturbances.

My concern with this program is that it is not clear that the Company has fully defined exactly what kind of investments do and do not qualify as TSI. Without a proper definition, it is easy for the Company to fit routine projects under the TSI umbrella. In fact, during project planning, the Company will often combine multiple projects in order to gain operational efficiencies and make several necessary repairs during an outage. While there may not be an intent to mask or disguise certain expenditures, the fact is that this practice makes them difficult to identify and track.

In my investigation, I reviewed additional documentation for four projects for which DEP seeks cost recovery in this proceeding, all classified as TSI, totaling $5.6 million. As discussed further below, the basis by which DEP classified these projects as TSI appears questionable.

Q. CAN YOU PLEASE ELABORATE ON YOUR FINDINGS?

A. Yes. In one project, DEP capitalized $2 million spent to install a power line carrier to enable redundant coverage with instantaneous tripping for the Blewett Plant-Rockingham 115kV line. The Company's basis for including this project as TSI is as follows: "This is a resiliency project that enables remote monitoring and visibility of the Transmission system and improves the ability to quickly isolate faults on the system to minimize customer impacts."[88] With this definition, literally any modern resiliency project could be lumped into the TSI program and, if the Commission approves DEP's deferral request, would receive deferred accounting.

Additionally, DEP capitalized $1.5 million spent to replace line relay protection panels for several 230 kV lines, along with replacing the digital fault recorder.[89] While replacing electromechanical relays with digital relays is indeed part of the TSI program, replacing an existing digital fault recorder should not be classified as TSI. This appears to be an example of overlap between GIP and routine costs, and my concern is that without a cap on the TSI program, it is inevitable that routine, non-GIP costs will be classified as TSI and will be granted accounting deferral (assuming the Commission approves DEP's request).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that, if the Commission determines that the TSI program should be granted accounting deferral, DEP should not be permitted to defer any amount of capital expenses classified as TSI in excess of $23.7 million (the three-year total presented in Oliver Exhibit 10). For DEC, this number would be $62.7 million.[90] If the Companies believe that a

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[88] *See* DEP response to PS DR 126-5, attached as Thomas Exhibit 9.

[89] *Id.*

[90] This is a position I did not take in the DEC general rate case, however I believe that a cost cap on Transmission System Intelligence (TSI) would be appropriate for both jurisdictions, given what I have learned.

modification to the caps is necessary, they would be able to request a change in their next general rate case.

Q. BASED UPON YOUR INVESTIGATION, DO YOU BELIEVE GIP CBA ESTIMATES, AND THE COST ESTIMATION PROCESS IN GENERAL, IS LIKELY TO BE ACCURATE?

A. It is difficult to come to a conclusion regarding the accuracy of cost estimates, but I am not convinced that the process DEP is using to estimate GIP costs will yield accurate figures. This may lead to distorted project economics and approval of projects in the early stages that are not cost effective. After the project has begun, the presence of sunk costs makes it difficult for that project to ever be later cancelled due to lack of cost-effectiveness. In addition, cost estimates in the CBA did not always accurately align with actual costs in the field.

Q. CAN YOU GIVE SOME EXAMPLES OF YOUR FINDINGS?

A. In my review, I found several GIP projects where significant portions of the final project cost, such as labor, engineering and design, environmental protection, and telecommunication requirements, were left out of the initial cost estimates. I also found several Transmission H&R Line Projects that were included in the GIP CBAs, despite the majority of the project spend being excluded from the CBA because it was spent prior to 2019.[91] At least

[91] The Public Staff advises DEP to file an updated Oliver Exhibit 10 reflecting the removal of these projects, totaling $11 million, from GIP.

one project placed in service, at $1.7 million, was erroneously labeled as Transmission H&R; DEP states that this project should have actually been included as Transmission System Intelligence. These errors and inconsistencies raise doubts in my mind about the accuracy of the GIP budget proposed in Oliver Exhibit 10.

Q. DO YOU HAVE CONFIDENCE THAT ANY OF DEP'S CBAs ACCURATELY ESTIMATE PROGRAM COSTS?

A. Yes. DEP provided information that indicated that the actual costs of the Distribution Transformer Retrofit program and the Hydraulic to Electronic Recloser subprogram were very close to the estimates used in the CBA. This is expected, as these two programs have been ongoing for some time.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE COSTS OF GIP THAT DEP IS REQUESTING FOR RECOVERY?

A. Yes. My findings raise concerns that the Company does not currently have the ability to accurately track GIP costs by program, and that individual GIP projects may end up being approved based on incomplete cost estimates. While I have only found several instances of errors, misclassifications, and incomplete cost estimates, I also only reviewed a sample of the total GIP costs in this proceeding. I recommend that the Company commit to improving its cost tracking methodology so that these costs can be reviewed in the context of the Company's GIP proposal in future rate cases. This cost tracking methodology should (1) separate costs by program for projects that encompass multiple programs; and (2) separate GIP costs from other T&D costs in a more robust fashion than is currently being done.

Regarding the cost estimate issue, I would first state that any GIP project that was approved to move forward based upon incomplete cost estimates would be, in my opinion, imprudent. In this proceeding, I found several projects that had incomplete cost estimates, but I have not yet linked those to approvals based upon those cost estimates. In future rate recovery proceedings, the Public Staff will be closely monitoring this issue, and I recommend that the Company commit to ensuring that each GIP project executed has a full and complete cost estimate.

V. Recommendations

Q. ARE YOU MAKING ANY RECOMMENDATIONS TO THE COMMISSION?

A. Yes. I have several recommendations, based upon my review of the Company's CBAs.

1. To assist in the evaluation of GIP program benefits and cost recovery, the Company should be required to track and annually report the progress of GIP implementation throughout the 3-year plan and beyond, including actual expenditures, changes in program scope, and Evaluation, Measurement, and Verification of claimed

benefits.[92] In addition, costs related to GIP should be booked, tracked, and reported separately from other T&D investments, and projects covering multiple GIP programs should have their costs broken out by GIP program.

2. The Company should perform CBAs for some GIP programs that were not evaluated for cost-effectiveness, such as Distribution Automation, DER Dispatch, and any others that the Commission deems appropriate.

3. The Company should be required to file sensitivity analyses of its CBAs, which should explore variations in multiple input variables. These sensitivity analyses should include, at a minimum, capital costs, O&M costs, fuel and related benefits, and customer interruption costs, along with any other parameters the Commission deems appropriate. These analyses should discuss the risk of benefit shortfalls and cost overruns, and provide plans on how GIP implementation will be modified if either occurs.

4. In light of the limitations of the LBNL Report, the Company should consider if there is value in conducting an interruption cost study in the Carolinas that would more accurately reflect interruption costs experienced by its customers than the LBNL Report. This study could

[92] These reports might take a similar format as the annual reports DEP files for its DSDR program in Docket No. E-2, Sub 926, although the Public Staff recommends that DEC work with stakeholders to ensure the appropriate key metrics are being tracked and reported.

be conducted with the cooperation of LBNL, with a new region-specific interruption cost model being the ultimate goal.

5. The Company should remove or modify certain benefits from its CBAs, including long duration reliability benefits over 24 hours, asset management benefits, and CO_2 emission savings.

6. The Company should revise its SOG CBAs to include the effect of momentary outages as a result of automatic circuit reconfiguration.

7. The Company should revise its SOG CBA to adjust the faults per mile variable, taking into account the expected reduction in vegetation-related outages resulting from the increased pace of vegetation management proposed in this proceeding.

8. The Company should consider the impact of GIP programs on costs not considered, such as M&S inventory, and factor those impacts (if any) into its CBAs.

9. DEP should reduce the scope of the DSDR to CVR Conversion project and identify the minimum amount of investment required to determine that the conversion is a net benefit to ratepayers, particularly in light of lost winter peak shaving capabilites.

10. DEP should consider reducing the deployment of its early asset replacement programs (Transformer Bank Replacement and Oil Breaker Replacement), so that customers do not bear costs for unnecessary early asset replacements.

11. DEP should include the cost of repairing faults on underground lines in its TUG CBA.

12. The Commission and the Company should consider if changes to GIP cost allocations are warranted, in light of the benefit allocation discussed herein.

13. If the Commission determines that the Transmission System Intelligence program should be granted accounting deferral, DEP should be permitted to defer no more $23.7 million over the next three years.

Q. CAN YOU SUMMARIZE THE IMPACT OF YOUR RECOMMENDATIONS ON THE COMPANY'S CBAs?

A. I have been able to estimate the impact on the entire GIP proposal of the following recommendations: (1) removal of CO_2 benefits from DSDR and IVVC; (2) inclusion of momentary outages in SOG; and (3) capping long duration outages on the DTR program. I was unable to estimate the impact of other changes I have recommended, such as capping long duration outages in TUG, Transmission H&R, and LDI/HIS programs, or including the cost of repairing faults on underground lines in TUG. I have summarized the cumulative impact of four recommendations enumerated above in Table 9 below (only SOG, IVVC, DTR, and DSDR were changed).

Table 8: Summary of the impact of PS Recommendations.

Description	Benefits As Filed		Benefits with PS Recommendations	
	BCR	**% Customer Reliability Benefits**	**BCR**	**% Customer Reliability Benefits**
SOG (DEP)	3.1	93%	**1.6**	**93%**
DTR (DEC+DEP)	1.5	96%	**1.4**	**96%**
IVVC (DEC)	1.2	0%	**0.9**	**0%**
DSDR (DEP)	35.3	0%	**27.8**	**0%**
Trans Line H&R (DEP)	3.3	100%	3.3	100%
Transformer Bank Replacements (DEP)	0.8	20%	0.8	20%
Oil Breaker Replacements (DEP)	1.6	74%	1.6	74%
TUG (DEP+DEC)	12.1	92%	12.1	92%
LDI / HIS (DEP+DEC)	29.4	100%	29.4	100%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JEFFREY T. THOMAS

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science in General Engineering. Afterwards, I worked in various operations management roles for General Electric, United Technologies Corporation, and Danaher Corporation. Originally, a manufacturing and process engineer in GE's Operations Management and Leadership program, I eventually became a production supervisor, where I was responsible for the safety and productivity of a team of employees. I left manufacturing in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering. At NC State, I performed cost-benefit analysis evaluating smart grid components, such as solid-state transformers and grid edge devices, at the Future Renewable Energy Electricity Delivery and Management Systems Engineering Research Center. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have filed testimony in avoided cost proceedings, general rate cases, and CPCN applications, and have been involved in the implementation of HB 589 programs, utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation.

Abbreviations List

AACE	American Association of Cost Engineering
ADMS	Advanced Distribution Management System
ALD	Automatic Lateral Device
AMB	Asset Management Benefit
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
BCR	Benefit Cost Ratio
C&I	Commercial and Industrial
CBA	Cost Benefit Analysis
CEMI-6	Customers Experiencing Multiple Interruptions
CI	Customer Interruptions
CIP	Critical Infrastructure Protection
CMI	Customer Minutes Interrupted
COSS	Cost of Service Study
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Data Request
DRP	Distribution Resource Planning
DSDR	Distribution System Demand Response
DSM	Demand Side Management
DSPx	Next Generation Distribution System Platform
DTR	Distribution Transformer Retrofit
EDSH	Enterprise Distribution System Health
EE	Energy Efficiency
ET	Electric Transportation
GIP	Grid Improvement Plan
GRR	Grid Reliability and Resiliency (Rider)
H&R	Hardening and Resiliency
HRM	Health and Risk Monitoring
ICE	Interruption Cost Estimator
IRP	Integrated Resource Plan
ISOP	Integrated System Operations Planning
IVVC	Integrated Volt Var Control

LBNL	Lawrence Berkeley National Laboratory
LDI / HIS	Long Duration Impact / High Impact Sites
M&S	Materials and Supplies
MED	Major Event Day
NASUCA	National Association of State Utility and Consumer Advocates
NC	North Carolina
NERC	North American Reliability Corporation
NPV	Net Present Value
O&M	Operations and Maintenance
OCB	Oil-filled Circuit Breakers
PFC	Power Forward Carolinas
PNNL	Pacific Northwest National Laboratory
PRMR	Planning Reserve Margin Requirement
PURPA	Public Utilities Regulatory Policies Act
QF	Qualified Facility
RESTORE	Regional Equipment Sharing for Transmission Outage Restoration
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Summer Coincident Peak
SOG	Self-Optimizing Grid
SWPA	Summer/Winter Peak and Average
T&D	Transmission and Distribution
TMT	Targeted Management Tool
TUG	Targeted Undergrounding
UCT	Utility Cost Test
VEPCO	Virginia Electric and Power Company
VM	Vegetation Management
VVO	Volt Var Optimization
WTA	Willingness to Accept
WTP	Willingness to Pay

(Exhibits JRW-1 through JRW-10 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct with Appendix A and B and supplemental testimony supporting second partial stipulation of J. Randall Woolridge were moved at the consolidated hearing and copied into the record as if given orally from the stand.)

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Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Public Staff - North Carolina Utilities Commission (Public Staff) to provide an overall fair rate of return or cost of capital recommendation for Duke Energy Progress, LLC (DEP or Company).[1]

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[1] In my testimony, I use the terms "rate of return" and "cost of capital" interchangeably. This is because the required rate of return of investors on a company's capital is the cost of capital.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I summarize my cost of capital recommendation for the Company, and review my primary areas of contention with the Company's position. Second, I discuss the proxy groups that I have used to estimate an equity cost rate for DEP. Third, I review the Company's proposed capital structure and debt cost rate. Fourth, I explain my calculation of my estimate of the appropriate equity cost rate for the Company. Finally, I critique DEP witness Hevert's rate of return analysis and testimony. Appendix A is a summary of my education and business experience.

A. Overview

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. A return on equity (ROE) is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products and services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and products. For a regulated monopoly, the regulator determines the level of profit available to the public utility. The United States Supreme Court established the guiding principles for determining an appropriate level of profitability for regulated public utilities in two cases: (1) *Hope*[2] and (2) *Bluefield*.[3] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Thus, calculating the appropriate ROE for a regulated utility requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using market data of similar-risk firms, the rate of return on equity investors require for that risk-class of firms in order to set an appropriate ROE for a regulated firm.

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[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

[3] *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).

B. Summary of Positions

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

A. The Company has proposed use of a hypothetical capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.15% as set out in the testimony of Company witness Newlin. Company witness Hevert has recommended a common equity cost rate of 10.50%. Thus, the Company's overall proposed rate of return is 7.52%.

Q. HOW HAVE YOU CONDUCTED YOUR RATE OF RETURN STUDIES FOR THE COMPANY?

A. I reviewed the Company's proposed capital structure and overall rate of return or cost of capital. The Company's proposed capital structure has a higher common equity component than the capital structure of its parent, Duke Energy Corporation (Duke Energy), as well as the averages of my proxy group of electric utilities (Electric Proxy Group) and Mr. Hevert's proxy group (Hevert Proxy Group). Therefore, as my primary recommendation, I am proposing a capital structure of 50.0% common equity and 50.0% debt, which is more consistent with the capital structures of comparable electric utility companies. To estimate an equity cost rate for the Company, I have applied the Discounted Cash Flow Model (DCF) and the Capital Asset Pricing

Model (CAPM) to the Electric Proxy Group. I have also applied the DCF and CAPM to the Hevert Proxy Group for comparison purposes.

Q. WHAT IS YOUR PRIMARY RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. My equity cost rate studies indicate that an appropriate ROE for the Company is in the range of 6.90% to 8.40%. I believe that this range accurately reflects current capital market data and the market cost of equity capital.[4] However, given that I am recommending a capital structure with a lower common equity ratio and higher financial risk than proposed by the Company, as a primary ROE for DEP, I am recommending an ROE of 9.0%. I am also recommending a long-term debt cost rate of 4.11%, which is the Company's actual embedded cost of debt as of December 31, 2019. Given my recommended capitalization ratios and debt cost rate, my rate of return or cost of capital recommendation for the Company is 6.56% and is summarized in Table 1 and Panel A of Exhibit JRW-1.

[4] As discussed in later in my testimony, by ‘current' market conditions I mean the pre-coronavirus market conditions. As detailed in Appendix B, I believe that markets at this time are in disequilibrium due to the tremendous uncertainty associated with the coronavirus and therefore the traditional DCF and CAPM models do not provide reliable measures of the equity cost rates at this time.

Table 1
Public Staff's Primary Rate of Return Recommendation

Capital Source	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	**50.00%**	**4.11%**	**2.06%**
Common Equity	**50.00%**	**9.00%**	**4.50%**
Total Capitalization	**100.00%**		**6.56%**

Q. ARE YOU ALSO PROVIDING AN ALTERNATIVE RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. Yes. My alternative rate of return recommendation uses DEP's actual capital structure as of December 31, 2019, which consists of 48.50% long-term debt and 51.50% common equity. With respect to the ROE, as indicated above, I believe that my equity cost rate range, 6.90% to 8.40%, accurately reflects current capital market data. As discussed below and in Appendix B, due to the tremendous impact of the coronavirus on the economy and financial markets, I have used pre-coronavirus financial markets data. Capital costs in the U.S. have been and remain low, with low inflation and interest rates and very modest economic growth. To reflect these low capital costs, my alternative ROE recommendation is 8.40%, which is at the high end of my equity cost rate range. Given my recommended capitalization ratios and recommended debt capital cost rate, my alternative rate of return or cost of capital recommendation for the Company is 6.32% and is summarized in Table 2 and Panel B of Exhibit JRW-1.

Table 2
Public Staff's Alternative Rate of Return Recommendation

Capital Source	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.50%	4.11%	1.99%
Common Equity	51.50%	8.40%	4.32%
Total Capitalization	100.00%		6.32%

C. Primary Rate of Return on Equity Issues

Q. PLEASE PROVIDE AN OVERVIEW OF THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The primary issues related to the Company's rate of return include the following:

Capital Structure – The Company has proposed a hypothetical capital structure consisting of 47.00% long-term debt and 53.00% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups as well as the actual capital structures of DEP and DEP's parent, Duke Energy. In my primary rate of return recommendation, I recommend adjusting DEP's proposed capital structure to use a common equity component of 50.0%, as that is more in line with the capital structures of the utilities in both proxy groups as well as DEP's parent, Duke Energy. In my alternative rate of return recommendation, I use DEP's actual capital structure as of December 31, 2019, which includes a common equity ratio of 51.5%.

In this case, I employ a lower ROE to reflect the higher common equity component in the capital structure and lower financial risk of the Company's actual capitalization.

Embedded Cost of Debt – The Company proposes to use as its embedded cost of long-term debt its rate as of December 31, 2018. Since that time, its debt costs have come down, and it is appropriate and fair to ratepayers that a more current cost of long-term debt be used.

Capital Market Conditions – Mr. Hevert's analyses, ROE results, and recommendations reflect an assumption of higher interest rates and capital costs that is inconsistent with current trends. Despite the Federal Reserve's moves to increase the federal funds rate over the 2015-18 time period, interest rates and capital costs remained at low levels. In 2019, interest rates fell dramatically with slow economic growth and low inflation. The Federal Reserve cut the federal fund rate three times in July, September, and October, and the 30-year yield traded at all-time low levels. In 2020, interest rates have again fallen to record low levels, with investors being very concerned over the impact of the coronavirus. In response, the Federal Reserve cut the federal fund rate by 50 basis points on March 3rd, and then another 50 basis points on March 15th. This issue is addressed in Appendix B.

The Company's ROE Analysis is Out-of-Date - The Company's ROE study was prepared in August 2019, about eight months ago. Since that time, the Federal Reserve has cut the federal funds rate three times and the 30-year Treasury rate has fallen over seventy basis points. Capital costs are much lower now, not only than when the Company's ROE study was prepared, but also than when the request to increase rates was filed.

DEP's Investment Risk is Below the Averages of the Two Proxy Groups – Mr. Hevert cites the Company's capital expenditures and North Carolina's regulatory environment to imply that DEP is riskier than his proxy group. However, his assessment of DEP's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DEP's Standard & Poor's (S&P's) and Moody's credit ratings suggest that the Company's investment risk is below the averages of the proxy groups.

Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.50% ROE Recommendation – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.50% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.50% are some of his CAPM/Empirical CAPM (ECAPM) results, which, as I explain later in my testimony, are derived from seriously flawed analyses. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) primarily *Value Line* data. Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.50% ROE recommendation.

DCF Equity Cost Rate - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. I have three central issues regarding Mr. Hevert's DCF analysis: (1) Mr. Hevert has given very little weight to his constant-growth DCF results in determining his recommended ROE; (2) he has claimed that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields; and (3) he relies exclusively on the overly optimistic and upwardly biased earnings per share (EPS) growth rate forecasts of Wall Street analysts and *Value Line*. By comparison, my DCF growth rate is supported by 13 growth rate measures including historical and projected growth rate measures and my evaluation of growth in dividends, book value, and earnings per share of proxy group companies.

CAPM Approach - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are two primary issues with Mr. Hevert's CAPM analyses: (1) he has employed an ad hoc version of the CAPM, the ECAPM, which is a model untested in academic and professional research, and which makes inappropriate adjustments to the risk-free rate and the market risk premium and; and (2) he uses market risk premiums of 12.05% and 12.19% that are excessive and do not reflect prospective market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and market risk premium. These EPS growth-rate projections and the resulting expected market returns and market risk premiums include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

Alternative Risk Premium Model - Mr. Hevert estimates an equity cost rate using an alternative risk premium model which he calls the Bond Yield Risk Premium (BYRP) approach. The risk premium in his BYRP method is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach including: (1) it is a gauge of commission behavior and not investor behavior; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium; he uses historical authorized ROEs and Treasury yields, and applies the resulting risk premium to projected Treasury yields; and (3) the risk premium is inflated as a measure of investor's required risk premium because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

<u>Expected Earnings Approach</u> - Mr. Hevert also uses the Expected Earnings approach to corroborate his recommended equity cost range for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group as well as for *Value Line*'s universe of electric utilities. Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's Expected Earnings approach in determining the appropriate ROE for DEP.

<u>Other Issues</u> - Mr. Hevert also considers two other factors in arriving at his 10.50% ROE recommendation. Mr. Hevert has cited as risk factors environmental regulations, in particular those relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering. However, these risk factors are already considered in the credit-rating process used by major rating agencies. As I noted

above, DEP's investment risk as measured by S&P and Moody's is below the average of the proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE recommendation of 10.50%. However, he has not identified any expected flotation costs for DEP.[5]

<u>North Carolina Economic Conditions</u> – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DEP's proposed ROE of 10.50% is fair and reasonable to DEP, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree that prior to the onset of the coronavirus, economic conditions had improved in North Carolina, the likely economic impact of the coronavirus on the economy of North Carolina and DEP's ratepayers clearly does not justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DEP's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-20 time period; (2) while the unemployment rates in North Carolina and DEP's service territory have fallen since their peaks in the 2009-2010 period, the unemployment rates in North Carolina (4.20%) and DEP's Service territory (4.87%) are both well above the

[5] In NC, flotation costs cannot lawfully be recovered when the Company does not expect to issue stock in the near future. Utilities Com. v. Public Staff, 331 N.C. 215; 415 S.E.2d 354 (1992).

national average (3.70%); and (3) while North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.[6] In addition, these figures do not reflect the prospective impact on unemployment and household income of the coronavirus.

II. Capital Market Conditions and Authorized ROEs

Q. PLEASE REVIEW THE FEDERAL RESERVE'S DECISIONS TO RAISE THE FEDERAL FUNDS RATE IN RECENT YEARS.

A. On December 16, 2015, the Federal Reserve increased its target rate for federal funds from 0.25 to 0.50 percent.[7] This increase came after the rate was kept in the 0.00 to 0.25 percent range for over five years in order to spur economic growth in the wake of the financial crisis associated with the Great Recession. As the economy improved, with lower unemployment, steady but slow Gross Domestic Product (GDP) growth, the Federal Reserve has increased the target federal funds rate on eight additional occasions: December 2016; March, June, and December of 2017; and March, June, September, and December of 2018.

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[6] Given the events associated with the coronavirus in 2020, unemployment is likely to increase and household income is likely to decline this year.

[7] The federal funds rate is set by the Federal Reserve and is the borrowing rate applicable to the most creditworthy financial institutions when they borrow and lend funds overnight to each other.

Q. HOW HAVE LONG-TERM RATES RESPONDED TO THE ACTIONS OF THE FEDERAL RESERVE?

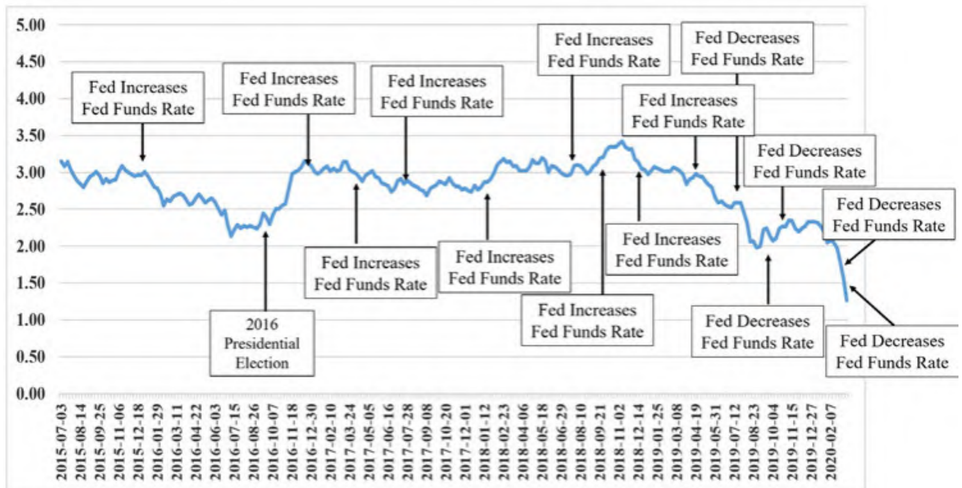
A. Figure 1, below, shows the yield on 30-year Treasury bonds over the period of 2015-2020. I have highlighted the dates when the Federal Reserve increased the federal funds rate. The 30-year Treasury yield hit its lowest point in the 2015-2016 timeframe in the summer of 2016 and subsequently increased with improvements in the economy. Financial markets moved significantly in the wake of the results of the presidential election on November 8, 2016. The stock market gained more than 10% and the 30-year Treasury yield increased about 50 basis points to 3.2% by year-end 2016. However, over the past three years, even as the Federal Reserve has increased the federal funds rate, the yield on 30-year bonds remained in the 2.8% to 3.4% range through 2018. These yields peaked at 3.48% in November of 2018, shortly before the December 2018 rate increase by the Federal Reserve.

Q. PLEASE REVIEW LONG-TERM TREASURY YIELDS IN 2019 AND 2020.

A. Despite the Federal Reserve's efforts to stimulate the economy, economic growth and inflation remained low, even with record low unemployment levels. The rate increase in December of 2018 was seen by many as maybe too aggressive.[8] Also, with the imposition of trade tariffs aimed at China, economic growth and inflation in the U.S. remained at low levels. This led the Federal Reserve to cut the federal fund rate to the 2.0%-2.25% range in July of 2019. Thirty-year Treasury yields, which began the year in the 3.0% range, declined significantly in the second quarter and, in August, declined to record lows and even traded below 2.0%. The Federal Reserve cut the federal fund rate three times in July, September, and October, and the 30-year yield traded at all-time low levels. In 2020, interest rates have again fallen to record low levels, with investors being very concerned over the impact of the coronavirus. In response, the Federal Reserve cut the federal fund rate by 50 basis points on March 3rd, and then another 50 basis points on March 15th. This issue is addressed in Appendix B.

[8] Patti Domm, "Here's What Spooked the Market About the Fed Today,' CNBC Market Insider (December 19, 2018). https://www.cnbc.com/2018/12/19/fed-delivers-.html.

Figure 1
Thirty-Year Treasury Yield and
Federal Reserve Fed Funds Rate Increases
2015-2020



Q. WHY HAVE LONG-TERM TREASURY YIELDS REMAINED IN THE 1.5%-3.0% RANGE DESPITE THE FEDERAL RESERVE INCREASING THE FEDERAL FUNDS RATE?

A. While the Federal Reserve can directly affect short-term rates by adjustments to the federal funds rate, long-term rates are primarily driven by expected economic growth and inflation.[9] The relationship between short- and long-term rates is normally evaluated using the yield curve. The yield curve depicts the relationship between the yield-to-maturity and the time-to-maturity for U.S. Treasury bills, notes, and bonds. Figure 2, below, shows the yield curve on a semi-

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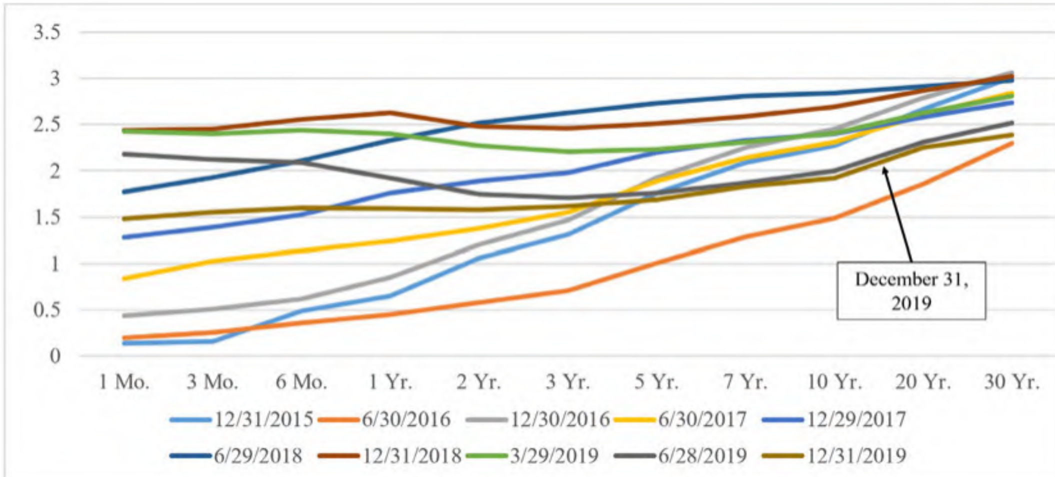
[9] While economic growth picked up in 2018, partly in response to the personal and corporate tax cuts, projected real GDP growth for 2019 and beyond remains in the 2.0% - 2.5% range. In addition, inflation remains low and is also in the 2.0% - 2.5% range.

annual basis since the Federal Reserve started increasing the federal funds rate at the end of 2015. It shows that, from the time the Federal Reserve began increasing the federal fund rate in 2015 and until 2018, with the exception of mid-year 2016, the 30-year Treasury yield remained in the 2.8%-3.4% range over this time frame despite the fact that short-term rates have increased from near 0.0% to about 2.50%. As such, long-term interest rates and capital costs did not increase in any meaningful way even with the Federal Reserve's actions and the increase in short-term rates.

In 2019 and again in 2020, with the large decline in long-term Treasury rates, the concern was an "inverted yield curve." An inverted yield curve occurs when short-term Treasury yields are above long-term Treasury yields and is commonly associated with a pending recession. The yield curve did invert a few times in the third quarter of 2019. In Figure 2, the yield curve for December 31, 2019, is shown in dark orange and is not inverted, due in large part to the three rate cuts.

Figure 2
Semi-Annual Yield Curves
2015-2019



Date Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO REGARDING MR. HEVERT'S FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS?

A. I suggest that the Commission disregard Mr. Hevert's forecasts and set an equity cost rate based on indicators of market-cost rates rather than speculating on the future direction of interest rates.

Economists have been predicting that interest rates would be going up for a decade, and they consistently have been wrong. Several studies in recent years have highlighted the bias in economists' forecasts toward higher interest rates: (1) after the announcement of the end of the Quantitative Easing III (QEIII) program in 2014, all of the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and 100% of the economists were wrong[10]; (2) *Bloomberg* reported that the Federal Reserve Bank of New York has gone as far as stopping use of interest rate estimates of professional forecasters in its interest rate model[11]; (3) a study entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," which evaluated economists' forecasts at the beginning of each year of the yield on ten-year Treasury bonds over the last ten years,[12] demonstrated that economists consistently predict that interest rates will go higher, and interest rates have not fulfilled the predictions; and (4) a study that tracked economists' forecasts for the yield on ten-year Treasury bonds on an ongoing basis from 2010 until 2015.[13] The results of this study, which was entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time," demonstrate how economists continually forecast that interest rates would rise, and they did not.

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[10] Ben Eisen, "Yes, 100% of economists were dead wrong about yields" *Market Watch*, October 22, 2014.https://www.marketwatch.com/story/yes-100-of-economists-were-dead-wrong-about-yields-2014-10-21.

[11] Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," *Bloomberg.com* (June 2, 2014). http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

[12] Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools," Bloomberg.com, March 16, 2015. http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

[13] Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

More recently, in an end-of-decade financial markets review series in the *Wall Street Journal*, Gregory Ip highlighted how economists' forecasts of higher interest rates over the 2010s continued to be erroneous. He provided evidence that economists forecast that short-term and long-term interest rates would go up, and these forecasts were consistently wrong. The article provides insights as to why the longest economic expansion on record that has resulted in a record-breaking stock market run and a 50-year low unemployment rate, was coupled with inflation that consistently ran below the Fed's 2% target and record low interest rates.[14] The bottom line – over the past decade - economists have consistently forecasted higher interest rates, and they have consistently been wrong!

Obviously, investors are aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. For example, consider a utility that pays a dividend of $2.00 with a stock price of $50.00. The current dividend yield in that example

[14] Gregory Ip, "Economists Got it Wrong for a Decade. They're Trying to Figure Out Why," *Wall Street Journal*, (December 14, 2019). P. C1.

is 4.0%. If, as Mr. Hevert suggests, interest rates and required utility yields increase, the price of the utility stock would decline. In the example above, if higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline to $40, which would be a -20% return on the stock. Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, it is practically impossible to accurately forecast interest rates and prices of investments that are determined in financial markets, such as interest rates and prices for stocks and commodities. For interest rates, I am not aware of any study that suggests one forecasting service is consistently better than others or that interest rate forecasts are consistently better than just assuming the current interest rate will be the rate in the future. As discussed above, investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. Thus, I recommend that the Commission not rely on interest rate forecasts but use current interest rates in estimating the appropriate ROE for the Company.

Q. PLEASE DISCUSS THE IMPACT OF THE CORONAVIRUS ON THE FINANCIAL MARKETS.

A. The financial markets around the world have been in chaos since the middle of February when the news of the spread of the coronavirus was recognized as a major risk factor for the world's population and global economy.[15] The coronavirus disease 2019 (COVID-19), which began in Wuhan, Hubei Province, China in December 2019, has spread to over 100 countries around the world, including the United States. As of late-March, the coronavirus was officially identified by the World Health Organization as a global pandemic, and there were hundreds of thousands of people reported infected and tens of thousands of deaths worldwide. Investors around the world began to focus on the potential economic consequences of the coronavirus in the middle of January.[16] However, the markets largely shrugged off the impact of the virus until the third week of February. Since that time, the S&P 500 has declined from almost 3,400, an all-time high, to about 2,700, over a 20% decline. The Dow Jones Utility Index ("DJU") has also declined by about 20% since mid-February. Over the same time period, investors fled to low risk financial assets, most notably long-term Treasury bonds. The yield on the benchmark 30-year Treasury bond declined from 2.0% to 1.5%, but has even traded

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[15] Appendix B provides a more detailed discussion of the impact of the coronavirus on estimating the cost of equity capital for public utilities.

[16] Akane Otane, "Coronavirus Tests Market's Faith in Global Economy" *Wall Street Journal*, January 28, 2019.

as low as 0.9%, an all-time low, between February and March. Furthermore, the day-to-day volatility of prices in financial markets has been at extremes. The VIX, which is the CBOE volatility index has increased from 15 to over 50 over the same period, a level which has not been seen since the financial crisis in 2008.

Q. GIVEN THESE CONDITIONS, WHAT IS YOUR OPINION ABOUT THE STATE OF THE CURRENT FINANCIAL MARKETS AND CAPITAL COSTS?

A. I believe that the emotions of the market and the great uncertainty over the future impact of the coronavirus have resulted in markets that have become disconnected from fundamentals.

Q. WHAT DO YOU MEAN BY FUNDAMENTALS?

A. Investors tend to focus various fundamental economic, industry, and company factors in assessing and developing risk and expected return expectations in alternative financial markets and securities. These factors include, but are not limited to, economy factors (such as GDP and industrial production growth, inflation, interest rates), industry factors (such as the sensitivity to overall economy, the product/service life cycle), and company specific factors (such as the execution of management, financial performance, and ultimately expected revenue and earnings growth rates).

Q. WHY DO YOU BELIEVE THAT THE MARKETS ARE NOT TRADING ON THESE FUNDAMENTALS?

A. The great uncertainty and risk associated with coronavirus – the virus spread and associated mortality and the duration of the pandemic and associated factors, and the overall impact on the global economy, is totally unknown at this point. The potential range of outcomes is huge. As a result, baseline forecasts for the economy, different industries, and ultimately individual companies are either unknown or highly uncertain. I believe that, in the current environment, investors cannot rely on fundamental factors to value stocks and bonds based on traditional valuation procedures and measures. Instead, I believe that investors are reacting to daily news reports and updates on the virus as to whether the situation is getting better or worse and then allocating their investment funds accordingly.

Q. GIVEN THE DISCUSSION ABOVE, AND THE CURRENT FINANCIAL MARKET SITUATION, WHAT DO YOU CONCLUDE ABOUT ESTIMATING THE COST OF EQUITY CAPITAL TODAY?

A. I believe that the current market situation makes it very difficult to get a reasonable estimate of the cost of equity capital, using current market data. These issues are addressed in more detail in Appendix B. I believe that the great volatility in the financial markets is a function of the emotions of the market and the great uncertainty over the future impact of the coronavirus. As a result, I believe that the markets have become disconnected from fundamentals. Therefore, using traditional cost of equity capital models, that depend on fundamental market data, are unlikely to provide a reasonable estimate of the cost of equity capital if they are based on data reflecting conditions that we face today.

Traditionally, there are three models used to estimate an equity cost rate for a public utility – the DCF, CAPM, and risk premium models. The issues with using these models in the markets today are summarized below:

(1) DCF Model – The ROE from the DCF model is the sum of the dividend yield and expected long-term growth rate. The dividend yield is readily observable since dividends and stock prices are directly observable. While dividend yields have increased due to the declined in utility stock prices, I believe estimating the long-term growth rate is a big question mark. The long-term growth rate is usually based, in part, on analysts' three-to-five-year EPS growth rate estimates. And while it is likely that these growth rates will be lowered due to the significant slowdown in economic growth associated with the coronavirus, the magnitude of any likely reduction is highly indeterminate due the great uncertainty involving

the spread of the virus and its impact on the economy. Therefore, while I usually rely primarily on the DCF model, I believe that it will not provide a reliable measure of a utility equity cost rate until analysts' have a better idea about the impact of the coronavirus on future growth.

(2) CAPM Approach – The CAPM has three components – the risk-free interest rate, beta, and the MRP. The impact of the decrease in the risk-free interest rate yield is directly observable. Betas are measured using historical returns and so are not impacted by the current environment. The impact of the current environment on the MRP is very uncertain. The MRP is measured as the E(RM) – RF. The MRP increases by the lower level of the risk-free interest rate. However, the impact of the current environment on E(RM) is highly uncertain. As noted, historical return and survey approaches to estimating the MRP would not capture the changes over the past month. And the expected return models would suffer from the same issue as the DCF model. Namely, estimates of the E(R) are very indeterminate, since these models normally rely, in large part, on analysts' forecasts of three-to-five-year EPS growth rates and, as discussed above, these forecasts would appear to be very difficult to make given the highly uncertain economic environment. I believe that this is even more true for the S&P 500 as opposed to regulated

utilities given the huge impact of the virus as such industries as travel, restaurants, hotels, aviation, autos, and other sectors tied to retail spending; and

(3) Risk Premium Approach – The ROE from a risk premium approach is the sum of the risk-free interest rate and a risk premium. As noted, the risk-free rate component is directly observable, and is lower in the current environment. The risk premium component of the model is usually computed using historical utility stock and bond returns or historical authorized utility ROEs minus the risk-free interest rate. Since both the stock and bond returns and the authorized ROEs approaches to estimating the risk premium component use historical data and hence do not change with the current environment, the risk premium is not impacted by the current environment. Therefore, the ROE using the general historical risk premium model is lower due to a lower risk-free interest rate currently.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE USE OF COST OF EQUITY CAPITAL MODELS IN THE CURRENT FINANCIAL MARKET SITUATION TO ESTIMATE THE COST OF EQUITY CAPITAL FOR A PUBLIC UTILITY TODAY?

A. Yes. Financial models such as the DCF and CAPM models are models developed theoretically in a normative sense with a number of simplifying and in many cases unrealistic assumptions. The application of such models in the real world is known as positive economics. That is, despite the unrealistic nature of some of the assumptions, economists apply the models to assess whether the models provide reasonable results. However, these models rely on the precondition of "In equilibrium . . ." In other words, the normative and positive forms of the model presume that the markets are in equilibrium. The big increase in volatility in the markets suggests that the markets are not in equilibrium, and probably will not be in equilibrium until more is known about the virus and the associated economic implications. As a result, I believe that security prices are disconnected from fundamentals due to the great uncertainty associated with the coronavirus, and therefore traditional financial models such as the DCF and CAPM models do not provide reliable estimates of the cost of equity capital in the coronavirus economic environment.

Q. HOW HAVE YOU TAKEN THESE OBSERVATIONS IN ACCOUNT IN ESTIMATING OF COST OF EQUITY CAPITAL FOR DEP?

A. I used the traditional DCF and CAPM models to estimate an equity cost rate for DEP. However, I have used data as of the first week of February, which is before the market meltdown associated with coronavirus. I believe that the volatility of the markets since mid-

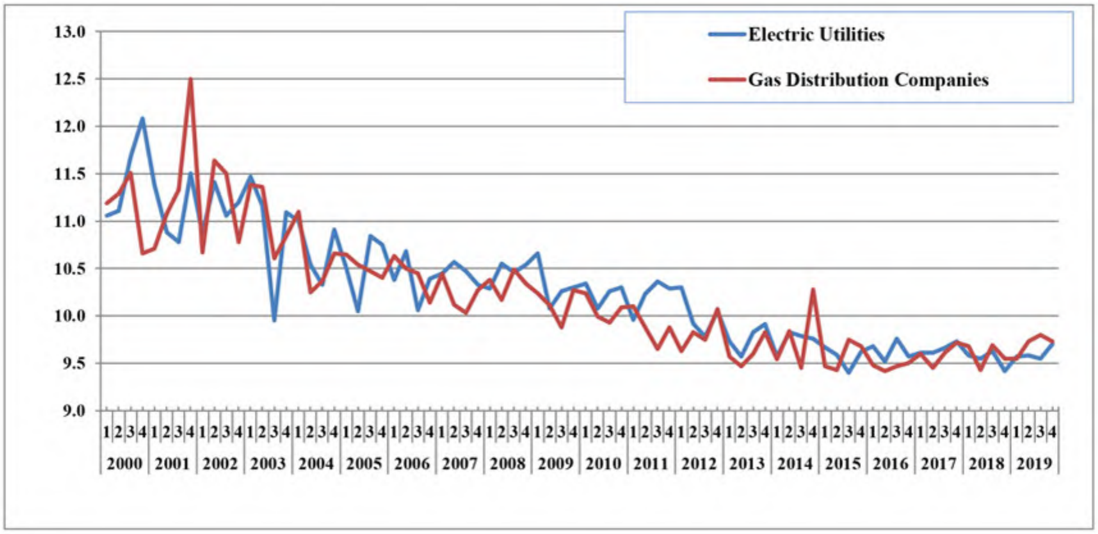
February suggest that the markets are not in equilibrium and therefore traditional models, using the current market data, do not provide reliable estimates of the cost of equity capital. In short, as summarized above, this uncertainty impacts the inputs to the primarily cost of equity capital models – including interest rates, stock prices, and expected growth rates - and there is not clear indication that these models would indicate that equity cost rates have increased or decreased since mid-February.

Q. PLEASE DISCUSS THE TREND IN AUTHORIZED RETURN ON EQUITY FOR ELECTRIC AND GAS COMPANIES.

A. Over the past five years, with historically low interest rates and capital costs, authorized ROEs for electric utility and gas distribution companies have slowly declined to reflect the low capital cost environment. In Figure 3, below, I have graphed the quarterly authorized ROEs for electric and gas companies from 2000 to 2019. There is a clear downward trend in the data. On an annual basis, these authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.64% in of 2019, according to Regulatory Research Associates.[17]

[17] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2019.

Figure 3
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2019



Q. DO YOU BELIEVE THAT YOUR ROE RECOMMENDATION MEETS *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes, I do. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Q. PLEASE ALSO DISCUSS YOUR RECOMMENDATION IN LIGHT OF A MOODY'S PUBLICATION ON ROES AND CREDIT QUALITY.

A. In an article published by Moody's on utility ROEs and credit quality, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates. The article explains:[18]

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, yet this is not impairing their credit profiles and is not deterring them from raising record amounts of capital.

With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower interest rates and cost recovery mechanisms:[19]

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[18] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

[19] *Id.*

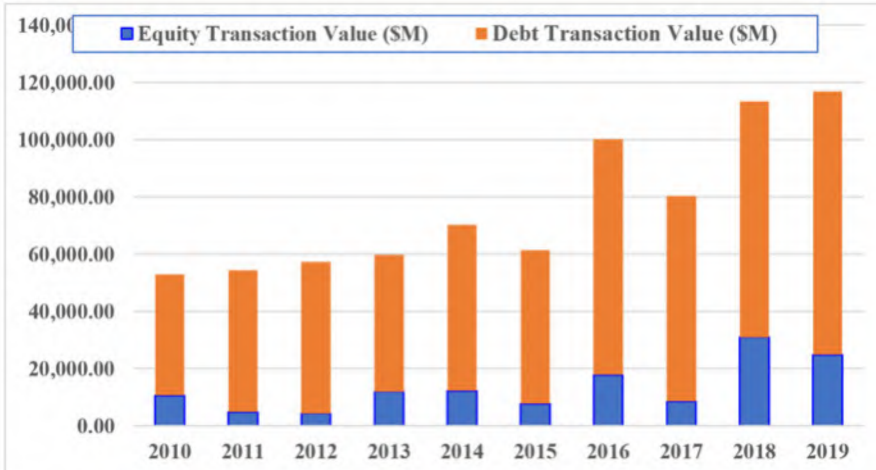
> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

Overall, this article further supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

Q. ARE UTILITIES ABLE TO ATTRACT CAPITAL WITH THE LOWER ROES?

A. Yes. Figure 4 shows the annual amounts of debt and equity capital raised by public utility companies over the past decade. Electric utility and gas distribution companies have taken advantage of the low interest rate and capital cost environment of recent years and raised records amount of capital in the markets. In fact, in each of 2018 and 2019, public utilities have raised a total of over $100 billion in debt and equity. Clearly, even with lower ROEs, utilities are able to attract record amounts of capital.

Figure 4
Debt and Equity Capital Raised by Public Utilities
2010-2019



Source: S&P Global Market Intelligence, S&P Cap IQ, 2020.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. To develop a fair rate of return recommendation for DEP, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies (Electric Proxy Group). I have also evaluated the group developed by Mr. Hevert (Hevert Proxy Group).

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. The selection criteria for the companies in Electric Proxy Group include the following:

(1) Received at least 50% of revenues from regulated electric operations as reported in SEC Form 10-K Report;

(2) Is listed as a U.S.-based Electric Utility by *Value Line Investment Survey*;

(3) Has an investment-grade corporate credit and bond rating;

(4) Has paid a cash dividend for the past six months, with no cuts or omissions;

(5) Is not involved in an acquisition of another utility, and not the target of an acquisition; and

(6) Has analysts' long-term EPS growth rate forecasts available from Yahoo or Zack's.

The Electric Proxy Group includes 31 companies. Summary financial statistics for the proxy group are listed in Exhibit JRW-2. The average operating revenues and net plant among members of the Electric Proxy Group are $8,745.8 million and $31,138.7 million, respectively. The group on average receives 80% of its revenues from regulated electric operations, and has a BBB+ bond rating from S&P's and a Baa1 rating from Moody's, a current average common equity ratio of 43.8%, and an earned return on common equity of 10.1%.

Q. PLEASE DESCRIBE THE HEVERT PROXY GROUP.

A. Mr. Hevert's group is smaller (19 companies). Summary financial statistics for Mr. Hevert's proxy group are provided in Panel B of page 1 of Exhibit JRW-2. The average operating revenues and net plant for the Hevert Proxy Group are \$6,900.3 million and \$24,776.2 million, respectively. The group on average receives 79% of its revenues from regulated electric operations, and has a BBB+ bond rating from S&P's and a Baa1 rating from Moody's, an average common equity ratio of 44.9%, and earned return on common equity of 10.2%.

Q. HOW DOES THE INVESTMENT RISK OF THE COMPANY COMPARE TO THAT OF YOUR ELECTRIC PROXY GROUP AND THE HEVERT PROXY GROUP?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. The S&P and Moody's issuer credit ratings for DEP are A- and A2, respectively. The average S&P and Moody's ratings for the Electric and Hevert Proxy Group are BBB+ and Baa1. Therefore, DEP's S&P rating is one notch above the average of the two groups (A- vs. BBB+), and DEP's Moody's rating is two rating notches above the average of the two groups (A2 vs. Baa1). This indicates that the investment risk of DEP is below the average of the electric utilities in the two proxy groups.

On page 2 of Exhibit JRW-2, I have assessed the riskiness of the two proxy groups using five different risk measures from *Value Line*. These measures are beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability.[20] These risk measures indicate that the two proxy groups are similar in risk. The comparisons of the risk measures of the Electric Proxy Group and the Hevert Proxy Group show beta (0.55 vs. 0.54), Financial Strength (A vs. A) Safety (1.8 vs. 1.8), Earnings Predictability (77 vs. 82), and Stock Price Stability (97 vs. 98), respectively. On balance, these measures suggest that the two proxy groups are similar in risk.

Q. WHAT DO YOU CONCLUDE FROM YOUR RISK ANALYSIS?

A. First, based on the credit ratings from S&P and Moody's, I conclude that the Company is less risky than the average of the two proxy groups. Second, the S&P and Moody's credit ratings and the five *Value Line* risk ratings are very similar for the two groups, and therefore I conclude that the two groups are similar in risk. And third, the five *Value Line* risk ratings for the two groups suggest that electric utilities are very low risk. This is indicated by the low betas as well as the high ratings for safety, financial strength, earnings predictability, and stock price stability.

[20] These risk metrics are described in detail on Page 3 of Exhibit JRW-2.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE DEP'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. DEP witness Newlin has proposed a hypothetical capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.15% based on its weighted average cost of long-term debt as of December 31, 2018.

Q. HOW DOES MR. NEWLIN DEVELOP THE COMPANY'S PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0%?

A. Mr. Newlin simply maintains that a capital structure with a common equity ratio of 53.0% is needed to ensure the financial integrity of DEP.

Q. HAS MR. NEWLIN PREPARED ANY STUDIES TO DEFEND HIS PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0%?

A. No.

Q. HAS MR. NEWLIN COMPARED THE COMPANY'S PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0% WITH THE CAPITAL STRUCTURE RATIOS OF OTHER ELECTRIC UTILITY COMPANIES?

A. No.

Q. HAS MR. NEWLIN TAKEN INTO ACCOUNT THE FACT THAT DEP'S S&P AND MOODY'S RATINGS OF A- AND A2 ARE ABOVE THE S&P AND MOODY'S RATINGS OF OTHER ELECTRIC UTILITIES?

A. No.

Q. HOW DO DEP'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE AVERAGE CAPITALIZATION RATIOS FOR COMPANIES IN THE PROXY GROUPS?

A. DEP's proposed capital structure ratios include a common equity ratio of 53.00%. As shown on Page 1 of Exhibit JRW-2, the average quarterly common equity ratio for the Electric and Hevert Proxy Groups as of December 31, 2019, was 43.8% and 44.9%, respectively. As such, DEP has proposed a capital structure that includes much more common equity in financing its utility operations than the average of the proxy group.

Q. IS IT APPROPRIATE TO USE THE COMMON EQUITY RATIOS OF THE PARENT HOLDING COMPANIES OR SUBSIDIARY OPERATING UTILITIES FOR COMPARISON PURPOSES WITH DEP'S PROPOSED CAPITALIZATION?

A. It is appropriate to use the common equity ratios of the utility holding companies because the holding companies are publicly-traded and their stocks are used in the cost of equity capital studies. The equities of the operating utilities are not publicly-traded and hence their stocks cannot be used to compute the cost of equity capital for DEP.

Q. IS IT APPROPRIATE TO INCLUDE SHORT-TERM DEBT IN THE CAPITALIZATION IN COMPARING THE COMMON EQUITY RATIOS OF THE HOLDING COMPANIES WITH DEP'S PROPOSED CAPITALIZATION?

A. Yes. I am following North Carolina precedent and not recommending short-term debt in DEP's capital structure. However, in comparing the common equity ratios of the holding companies with DEP's recommendation, it is appropriate to include short-term debt when computing the holding company common equity ratios. That is because short-term debt, like long-term debt, has a higher claim on the assets and earnings of the company and requires timely payment of interest and repayment of principal. In addition, the financial risk of a company is based on total debt, which includes both short-term and long-term debt. This is why credit rating agencies use total debt in assessing the leverage and financial risk of companies.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO AUTHORIZED FOR ELECTRIC UTILITIES BY STATE REGULATORY COMMISSIONS?

A. According to S&P Global Market Intelligence, the average authorized common equity ratio for electric utilities in calendar years 2018 and 2019 was 50.98%. This percentage excludes the common equity ratios of utilities in states which include cost-free capital items in authorized capital structures.[21]

Q. HOW DO DEP'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE CAPITALIZATION RATIOS OF DEP AND ITS PARENT, DUKE ENERGY?

A. DEP and Duke Energy's average quarterly common equity ratio for the eight quarters ending December 31, 2019 (as provided in Panel B on Page 1 of Exhibit JRW-3), were 52.5% and 43.9%, respectively. These figures exclude short-term debt in the total capitalization of DEP and Duke Energy. As a result, the Company's proposed capital structure includes a higher common equity ratio than it has maintained in the past two years and a much higher common equity ratio than its parent company, Duke Energy Corporation.

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[21] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2018 and 2019.

Q. IS DUKE ENERGY'S HIGH DEBT RATIO AND LOW EQUITY RATIO A FACTOR IN THE RISK ASSESSMENT OF DEP?

A. Yes. As previously noted, DEP's Moody's rating of A2 is two rating notches above Duke Energy's rating of Baa1.

Q. PLEASE DISCUSS THE ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DUKE ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY.

A. Moody's published an article on the use of low-cost debt financing by public utility holding companies to increase their ROEs. The summary observations included the following:[22]

> US utilities use leverage at the holding-company level to invest in other businesses, make acquisitions and earn higher returns on equity. In some cases, an increase in leverage at the parent can hurt the credit profiles of its regulated subsidiaries.

This financial strategy has traditionally been known as double leverage. Moody's defined double leverage in the following way:[23]

> Double leverage is a financial strategy whereby the parent raises debt but downstreams the proceeds to its operating subsidiary, likely in the form of an equity investment. Therefore, the subsidiary's operations are financed by debt raised at the subsidiary level and by

[22] Moody's Investors' Service, "High Leverage at the Parent Often Hurts the Whole Family," May 11, 2015, p.1.

[23] *Ibid.* p. 5.

> debt financed at the holding-company level. In this way, the subsidiary's equity is leveraged twice, once with the subsidiary debt and once with the holding-company debt. In a simple operating-company / holding-company structure, this practice results in a consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent.

Moody's goes on to discuss the potential risk to utilities of the strategy, and specifically notes that regulators could take it into consideration in setting authorized ROEs.[24]

> **"Double leverage" drives returns for some utilities but could pose risks down the road.** The use of double leverage, a long-standing practice whereby a holding company takes on debt and downstreams the proceeds to an operating subsidiary as equity, could pose risks down the road if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN A UTILITY'S CAPITAL STRUCTURE.

A. A utility's decision as to the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

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[24] *Ibid.* p. 1.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of dollars than it could raise with just equity. Debt is, therefore, a means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements that customers are called on to bear. Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. HOW HAVE UTILITIES TYPICALLY STRUCK THIS BALANCE?

A. Due to regulation and the essential nature of its output, a regulated utility is exposed to less business risk than other companies that are not regulated. This means that a utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. Thus, a utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirement.

Q. GIVEN THAT DEP HAS PROPOSED AN EQUITY RATIO THAT IS HIGHER THAN (1) THE AVERAGE COMMON EQUITY RATIOS OF THE ELECTRIC AND HEVERT'S PROXY GROUPS, (2) THE AVERAGE AUTHORIZED COMMON EQUITY RATIO FOR ELECTRIC UTILITY COMPANIES, AND (3) THE COMMON EQUITY RATIO OF ITS PARENT COMPANY, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated utility's actual capital structure contains a high equity ratio, the options are: (1) to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

Q. GIVEN THIS DISCUSSION, PLEASE DISCUSS YOUR PRIMARY CAPITAL STRUCTURE RECOMMENDATION FOR DEP.

A. My primary capital structure recommendation is presented in Panel C of Exhibit JRW-3. As previously noted, DEP's proposed capital structure consists of more common equity and less financial risk than any of the other proxy groups of electric companies. Therefore, in my primary rate of return recommendation, I am proposing a capital structure that includes a common equity ratio of 50.0%. This capital structure includes a common equity ratio that is about halfway between DEP's proposed capital structure of 53.00% and the average common equity ratios of the proxy groups of 43.80% and 44.90%. As shown in Table 3 and Panel C of Exhibit JRW-3, in this capital structure, I have grossed up the percentage amount of long-term debt to 50.0% and reduced the amount of common equity from 53.00% to 50.0%. As noted above, in my primary rate of return recommendation, I am using a ROE of 9.0%.

Table 3
Staff's Primary Capital Structure Recommendation

	DEP Proposed	Adjustment	Staff Proposed	Cost
Long-Term Debt	**47.00%**	**1.063830**	**50.00%**	**4.11%**
Common Equity	**53.00%**	**0.943396**	**50.00%**	**-**
Total Capital	**100.00%**		**100.00%**	

Q. DO YOU BELIEVE THAT YOUR PROPOSED 50% EQUITY CAPITAL STRUCTURE IS FAIR TO DEP?

A. Yes, for two reasons: (1) It includes a common equity ratio that is higher than the average common equity ratio for the Electric and

Hevert Proxy Groups and therefore affords DEP with more common equity and less financial risk than other electric utility companies; and (2) it is in line with the average authorized common equity ratios for the proxy groups of electric utility companies.

Q. WHAT IS THE CAPITAL STRUCTURE IN YOUR ALTERNATIVE RATE OF RETURN RECOMMENDATION?

A. In my alternative rate of return recommendation, I use DEP's actual capital structure as of December 31, 2019, which includes a common equity ratio of 51.5%. This is developed in Panel D of page 1 of Exhibit JRW-3. I am also using DEP's updated long-term debt cost rate of 4.15%. As noted above, in my alternative rate of return recommendation, I am using an ROE of 8.40%. I believe that the 8.40% ROE reflects the current market cost of equity. In addition, if the Commission adopts DEP's proposed capital structure with its high common equity ratio, I believe that the Commission should employ a lower ROE to reflect the lower financial risk associated with a higher common equity ratio.

Table 4
Public Staff's Alternative Capital Structure Recommendation

	Percent of Total	Cost
Long-Term Debt	**48.50%**	**4.11%**
Common Equity	**51.50%**	
Total Capital	**100.00%**	

Q. WHAT COST OF EMBEDDED LONG-TERM DEBT DO YOU RECOMMEND BE USED IN THESE PROCEEDINGS?

A. The Company's embedded cost of debt has been declining and I believe it is appropriate and fair to ratepayers to use a more current number. The Company used its December 31, 2018 rate of 4.15%, but I recommend using its December 31, 2019 cost of embedded long-term debt of 4.11%.

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services and the construction of utility infrastructure facilities, many public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility, *i.e.*, provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In a competitive market, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of those required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[25]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as

[25] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p.3.

> Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns a ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[26]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then*
Market/Book > 1	
If ROE = K	*then*
Market/Book =1	
If ROE < K	*then*
Market/Book < 1	

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using *Value Line*'s electric utilities and gas distribution companies. I used all electric utility and gas distribution companies that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Exhibit JRW-4. The R-square for the regression of estimated ROEs and market-to-book ratios is 0.50.[27] This demonstrates a statistically significant positive

[26] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

[27] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

relationship between ROEs and market-to-book ratios for electric utilities and gas companies. Given that the market-to-book ratios have been above 1.0 for a number of years, this also demonstrates that utilities have been earnings ROEs above the cost of equity capital for many years.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-5 provides indicators of public utility equity cost rates.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. The yields peaked in November 2008 at 7.75% during the Great Recession. These yields have generally declined since then, dropping below 4.0% on five occasions - in mid-2013, in the first quarter of 2015, in the summer of 2016, in late 2018, and in 2019. The yields were about 3.5% as of the end of 2019.

Page 2 of Exhibit JRW-5 provides the average dividend yields for electric utility companies over the past 16 years. The dividend yields for the electric group declined from 5.3% to 3.4% between 2001 and 2007, increased to over 5.0% in 2009, and have steadily declined since that time. The average dividend yield was 3.1% as of 2019.

Average earned returns on common equity and market-to-book ratios for electric utilities are shown on page 3 of Exhibit JRW-5. For the electric group, earned returns on common equity have declined gradually over the years. In the past three years, the average earned ROE for the group has been in the 9.0% to 10.0% range. The average market-to-book ratios for this group declined to about 1.1X in 2009 during the financial crisis and have increased since that time. As of 2019, the average market-to-book for the group was 2.10X. This means that, for at least the last decade, returns on common equity for electric utilities have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than necessary to support an appropriate profit level for regulated utilities.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business risk and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF PUBLIC UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Page 4 of Exhibit JRW-5 provides an assessment of investment risk for 97 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey.* The study shows that the investment risk of utilities is very low. The average betas for electric, gas, and water utility companies are 0.58, 0.67, and 0.68, respectively.[28] As such, the cost of equity for utilities is among the lowest of all industries in the U.S. based on modern capital market theory.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

[28] The beta for the *Value Line* Electric Utilities is the simple average of *Value Line*'s Electric East (0.56), Central (0.61), and West (0.59) group betas.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, determining the data inputs for these models, and interpreting the models' results. All of these decisions must take into consideration the firm involved, as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study; however, I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_1, D_2, and D_n are the dividends in year 1, 2, and the future years n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model (DDM). The stages in a three-stage DCF model are presented in Exhibit JRW-6. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly more attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. As I will explain below, the constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using the 3-stage model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where P is the current stock price, D_1 represents the expected dividend over the coming year, k is investor's required return on equity, and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates surrounds estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in Panels A and B of page 2 of Exhibit JRW-7. I have shown the mean and median dividend yields using 30-day, 90-day, and 180-day average stock prices. Using both the means and medians, the dividend yields range from 3.0% to 3.1% for the Electric Proxy Group and 2.8% to 3.0% for the Hevert Proxy Group. Therefore, I will use a dividend yields of 3.05% and 2.90% for the Electric Proxy Group and the Hevert Proxy Group, respectively.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates the dividend paid over the coming period to the current stock price. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[29]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

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[29] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half (1/2) of the expected growth to reflect growth over the coming year. The DCF equity cost rate (K) is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and projected growth rates for earnings and dividends per share and internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for EPS, dividends per share (DPS), and book value per share (BVPS). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (*i.e.*, business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by several different investment information services, including Institutional Brokers Estimate System (I/B/E/S), Bloomberg, S&L Global Market Intelligence FactSet, Zacks, First Call, and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. S&P, Bloomberg, FactSet, and Zacks each publish their own set of analysts' EPS forecasts for companies. These services do not reveal (1) the analysts who are solicited for forecasts or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. S&P, I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. In contrast, Thompson Reuters and Zacks do provide limited EPS forecast data free-of-charge on the Internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as MSN.money (http://money.msn.com).

Q. WHICH OF THE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. I am using the three-to-five-year EPS growth rate forecasts of analysts, which are often referred to as the long-term EPS growth rate forecasts.

Q. WHY DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a study by Lacina, Lee, and Xu has shown that analysts' three-to-five year EPS growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[30] Employing data over a 20-year period, these authors demonstrate that using the most recent year's actual EPS figure to forecast EPS in the next three-to-five years proved to be just as accurate as using the EPS estimates from analysts' three-to-five year EPS growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth-rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[31]

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[30] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited(2011), pp. 77-101.

[31] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance

Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[32]

Q. ARE THE PROJECTED EPS GROWTH RATES OF *VALUE LINE* ALSO OVERLY OPTIMISTIC AND UPWARDLY BIASED?

A. Yes. A study by Szakmary, Conover, and Lancaster evaluated the accuracy of *Value Line*'s three-to-five-year EPS growth rate forecasts using companies in the Dow Jones Industrial Average over a 30-year time period and found these forecasted EPS growth rates to be significantly higher than the EPS growth rates that these companies subsequently achieved.[33]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

Following Equity Offerings," *Contemporary Accounting Research* (2000)*;* K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance,* pp. 643−684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

[32] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

[33] Szakmary, A., Conover, C., & Lancaster, C. (2008). "An Examination of Value Line's Long-Term Projections," Journal of Banking & Finance, May 2008, pp. 820-33.

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth-rate forecasts, and therefore stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Because I believe that investors are aware of the upward bias in analysts' long-term EPS growth rate forecasts, stock prices reflect the bias. Thus, the DCF growth rate must be adjusted downward from the projected EPS growth rate to reflect this upward bias.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS, AS PROVIDED BY *VALUE LINE.*

A. Page 3 of Exhibit JRW-7 provides the five- and ten- year historical growth rates for EPS, DPS, and BVPS for the companies in the two proxy groups, as published in the *Value Line Investment Survey.* The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 4.0% to 5.0%, with an average of the medians of 4.4%. For the Hevert Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-7, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 4.5% to 6.5%, with an average of the medians of 5.0%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-7. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-7, the medians range from 5.0% to 5.5%, with an average of the medians of 5.3%. The range of the medians for the Hevert Proxy Group, shown in Panel B of page 4 of Exhibit JRW-7, is from 4.5% to 5.8%, with an average of the medians of 5.2%.

Also provided on page 4 of Exhibit JRW-7 are the prospective sustainable growth rates for the companies in the two proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and Hevert Proxy Groups, the median prospective sustainable growth rates are 3.6% and 3.5%, respectively.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED FIVE-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' five-year EPS growth-rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-7. I have reported both the mean and median growth rates for the groups. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the Electric and Hevert Proxy Groups are 5.0%/4.8% and 5.4%/5.4%, respectively.[34]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-7 shows the summary DCF growth rate indicators for the proxy groups.

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[34] Given variation in the measures of central tendency of analysts' projected EPS growth rates proxy groups, I have considered both the means and medians figures in the growth rate analysis.

The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 4.4%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.3%, and *Value Line*'s projected sustainable growth rate is 3.6%. The projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 5.0% and 4.8% as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 3.6% to 5.3%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.0%. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

For the Hevert Proxy Group, the historical growth rate indicators suggest a growth rate of 5.0%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.2%, and *Value Line*'s projected sustainable growth rate is 3.5%. The projected EPS growth rates of Wall Street analysts are 5.4% and 5.4% as measured by both the mean and median growth rates. The overall range for the projected growth rate indicators is 3.5% to 5.4%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.4%. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Hevert Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUPS?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-7 and in Table 5 below.

Table 5
DCF-Derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	3.05%	1.02500	5.00%	8.15%
Hevert Proxy Group	2.90%	1.02700	5.40%	8.40%

The result for the Electric Proxy Group is the 3.05% dividend yield, times the one and one-half growth adjustment factor of 1.02500, plus the DCF growth rate of 5.00%, which results in an equity cost rate of 8.15%. The result for the Hevert Proxy Group is 8.40%, which includes a dividend yield of 2.90%, a growth adjustment factor of 1.0270, and a DCF growth rate of 5.40%.

C. Capital Asset Pricing Model

Q. PLEASE DISCUSS THE CAPM.

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is expressed as:

$$\boldsymbol{K = (R_f) + ß * [E(R_m) - (R_f)]}$$

Where:

- *K* represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected rate of return on the overall stock market. Frequently, the S&P 500 is used as a proxy for the "market";

- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess rate of return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, the most difficult input to measure is the expected equity or market risk premium ($E(R_m) - (R_f)$). I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-8.

A. Exhibit JRW-8 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term

U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-8, the yield on 30-year U.S. Treasury bonds has been in the 1.6% to 4.0% range over the 2013–2020 time period. The current 30-year Treasury yield is near the bottom of this range. Given the recent range of yields, I have chosen to use a yield toward the high end of the range as my risk-free interest rate. Therefore, I am using 3.50% as the risk-free rate, or R_f, in my CAPM. This is a conservatively high estimate of the normalized risk-free interest rate, given that investment advisory firm Duff & Phelps also uses a normalized risk-free interest rate and Duff & Phelps is currently using 3.0% (see page 7 of Exhibit JRW-8.)[35].

Q. DOES YOUR 3.50% RISK-FREE INTEREST RATE TAKE INTO CONSIDERATION FORECASTS OF HIGHER INTEREST RATES?

A. No; it does not. As I stated before, forecasts of higher interest rates have been notoriously wrong for a decade. My 3.50% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market risk

[35] https://www.duffandphelps.com/insights/publications/cost-of-capital.

premium. The risk-free rate and the market risk premium are interrelated in that the market risk premium is developed in relation to the risk-free rate. As discussed below, my market risk premium is based on the results of many studies and surveys that have been published over time. Therefore, my risk-free interest rate of 3.50% is effectively a normalized risk-free rate of interest.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock with price movement greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-8, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-8, the median betas for the companies in both the Electric and Hevert Proxy Groups are 0.55.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM.

A. The market risk premium is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The market risk premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the market risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As is discussed below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[36]

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MARKET RISK PREMIUM.

A. Page 4 of Exhibit JRW-8 highlights the primary approaches to, and issues in, estimating the expected market risk premium. The traditional way to measure the market risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called *ex post* returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. However, this historical evaluation of returns can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market

[36] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, p. 3.

conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "*Ex Ante* Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[37]

In addition, there are a number of surveys of financial professionals regarding the market risk premium, as well as several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 200 CFOs participate in the survey.[38] Questions

[37] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics,* 145 (1985).

[38] DUKE/CFO Magazine Global Business Outlook Survey (https://www.cfosurvey.org).

regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters*.[39] This survey of professional economists has been published for almost 50 years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision-making.[40]

Q. PLEASE PROVIDE A SUMMARY OF THE MARKET RISK PREMIUM STUDIES.

A. Derrig and Orr, Fernandez, and Song completed the most comprehensive reviews of the research on the market risk premium.[41] Derrig and Orr's study evaluated the various approaches

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[39] Federal Reserve Bank of Philadelphia*, Survey of Professional Forecasters* (Mar. 22, 2019), https://www.philadelphiafed.org/-/media/research-and-data/real-time-center/survey-of-professional-forecasters/2019/spfq119.pdf?la=en. The Survey of Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[40] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School,* (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[41] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

to estimating market risk premiums, discussed the issues with the alternative approaches, and summarized the findings of the published research on the market risk premium. Fernandez examined four alternative measures of the market risk premium – historical, expected, required, and implied. He also reviewed the major studies of the market risk premium and presented the summary market risk premium results. Song provided an annotated bibliography and highlighted the alternative approaches to estimating the market risk premium.

Page 5 of Exhibit JRW-8 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the market risk premium. In developing page 5 of Exhibit JRW-8, I have categorized the types of studies as discussed on page 4 of Exhibit JRW-8. I have also included the results of studies of the "Building Blocks" approach to estimating the equity risk premium. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-8.

A. Page 5 of Exhibit JRW-8 provides a summary of the results of the market risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* market risk premium studies, (3) market risk premium surveys of CFOs, financial forecasters, analysts, companies and academics, and (4) the Building Blocks approach to the market risk premium. There are results reported for over 30 studies, and the median market risk premium of these studies is 4.83%.

Q. PLEASE HIGHLIGHT THE RESULTS OF MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-8 include every market risk premium study and survey I could identify that was published over the past 15 years and that provided a market risk premium estimate. Many of these studies were published prior to the financial crisis that began in 2008. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as 50 years of data) and so were not estimating a market risk premium as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the market risk premium, I have reconstructed page 5 of Exhibit JRW-8 on page 6 of Exhibit JRW-8; however, I have eliminated all studies dated before January 2, 2010. The median market risk premium estimate for this subset of studies is 5.13%.

Q. PLEASE SUMMARIZE THE MARKET RISK PREMIUM STUDIES AND SURVEYS.

A. As noted above, there are three approaches to estimating the market risk premium – historic stock and bond returns, ex ante or expected returns models, and surveys. The studies on page 6 of Exhibit JRW-8 can be summarized in the following manners:

Historic Stock and Bond Returns - Historic stock and bond returns suggest a market risk premium in the 4.40% to 6.43% range, depending on whether one uses arithmetic or geometric mean returns.

Ex Ante Models - Market risk premium studies that use expected or ex ante return models indicate a market risk premium in the range of 4.29% to 6.00%.

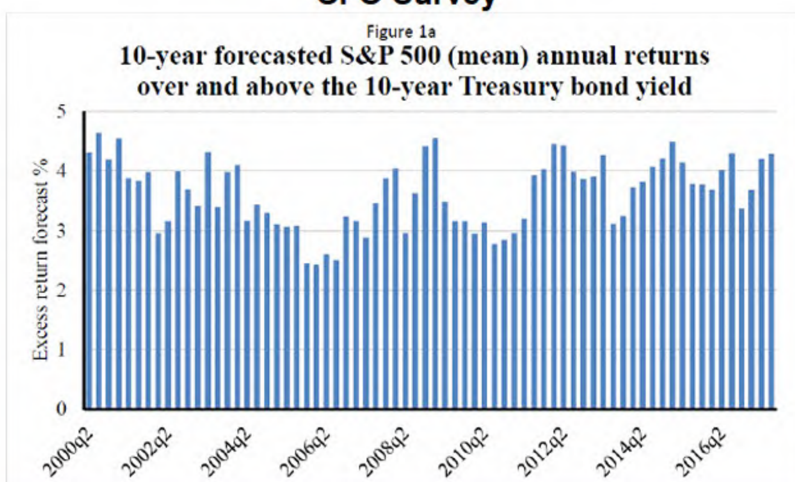
Surveys - Market risk premiums developed from surveys of analysts, companies, financial professionals, and academics are lower, with a range from 1.85% to 5.70%.

Q. PLEASE HIGHLIGHT THE EX ANTE MARKET RISK PREMIUM STUDIES AND SURVEYS THAT YOU BELIEVE ARE MOST TIMELY AND RELEVANT.

A. I will highlight several studies/surveys.

CFO Magazine conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. In the December 2019 CFO survey conducted by *CFO Magazine* and Duke University, which included approximately 400 responses, the expected 10-year market risk premium was 4.99% (with an expected S&P 500 stock return of 6.81% and a current 10-year Treasury yield of 1.82%).[42] Figure 6, below, shows the market risk premium associated with the CFO Survey, which has been in the 4.0% range in recent years.

Figure 6
Market Risk Premium
CFO Survey



Source:
https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162

[42] DUKE/CFO Magazine Global Business Outlook Survey, at 38, (December), https://www.cfosurvey.org/wp-content/uploads/2019/12/2019-Q4-US-Toplines.pdf.

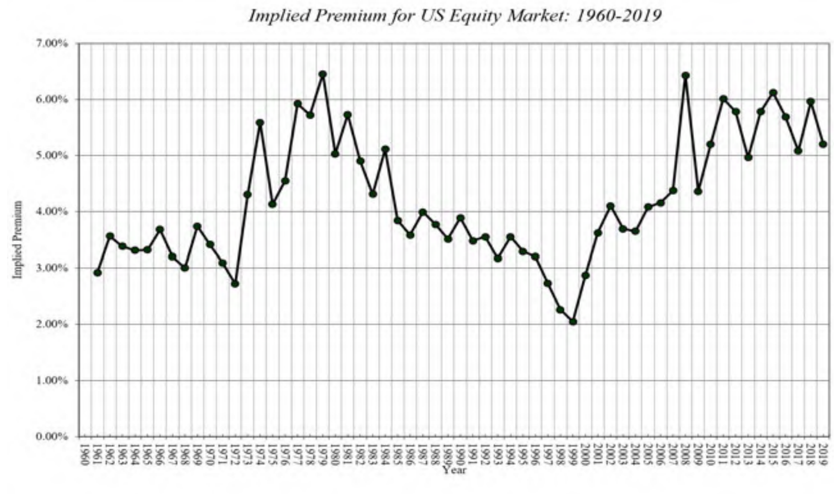
Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision-making.[43] His survey results are included on pages 5 and 6 of Exhibit JRW-8. The results of his 2019 survey of academics, financial analysts, and companies, which included 4,000 responses, indicated a mean market risk premium employed by U.S. analysts and companies of 5.6%.[44] His estimated market risk premium for the U.S. has been in the 5.00%-5.60% range in recent years.

Professor Aswath Damodaran of New York University, a leading expert on valuation and the market risk premium, provides a monthly updated market risk premium based on projected S&P 500 EPS and stock price level and long-term interest rates. His estimated market risk premium, shown graphically in Figure 5, below, for the past 20 years, has primarily been in the range of 5.0% to 6.0% since 2010.

[43] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School,* (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[44] *Ibid.* p. 3.

Figure 5
Damodaran Market Risk Premium



Source: http://pages.stern.nyu.edu/~adamodar/

Duff & Phelps, an investment advisory firm, provides recommendations for the risk-free interest rate and market risk premiums to be used in calculating the cost of capital data. Its recommendations over the 2008-2019 time periods are shown on page 7 of Exhibit JRW-8. Duff & Phelps' recommended market risk premium has been in the 5.0% to 6.0% range over the past decade. Most recently, in the fourth quarter of 2019, Duff & Phelps decreased its recommended market risk premium from 5.50% to 5.00%.[45]

KPMG is one of the largest public accounting firms in the world. Its recommended market risk premium over the 2013-2019 time period is shown in Panel A of page 8 of Exhibit JRW-8. KPMG's

[45] Duff & Phelps, "U.S. Equity Risk Premium Recommendation," (December, 2019), https://www.duffandphelps.com/insights/publications/cost-of-capital.

recommended market risk premium has been in the 5.50% to 6.50% range over this time period. In the first quarter of 2019, KPMG increased its estimated market risk premium from 5.50% to 5.75%.[46]

Finally, the website *market-risk-premia.com* provides risk-free interest rates, implied market risk premiums, and overall cost of capital for 36 countries around the world. These parameters for the U.S. over the 2002-2020 time period are shown in Panel B of page 8 of Exhibit JRW-8. As of January 31, 2020, *market-risk-premia.com* estimated an implied cost of capital for the U.S. of 5.65% consisting of a risk-free rate of 1.51% and an implied market risk premium of 4.14.[47]

Q. GIVEN THESE RESULTS, WHAT MARKET RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. The studies on page 6 of Exhibit JRW-8, and more importantly the more timely and relevant studies just cited, suggest that the appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range. I will use an expected market risk premium of 5.75%, which is in the upper end of the range, as the market risk premium. I gave

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[46] KPMG, "Equity Market Risk Premium Research Summary," (March 31, 2019), https://assets.kpmg/content/dam/kpmg/nl/pdf/2019/advisory/equity-market-risk-premium-research-summary-31032019.pdf.

[47] Market-Risk-Premia.com, "Implied Market-risk-premia (market risk premium): USA," http://www.market-risk-premia.com/us.html.

most weight to the market risk premium estimates of the CFO Survey, Duff & Phelps, KPMG, the Fernandez survey, and Damodaran. This is a conservatively high estimate of the market risk premium considering the many studies and surveys of the market risk premium.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-8 and in Table 6 below.

Table 6
CAPM-Derived Equity Cost Rate/ROE
$K = (R_f) + ß * [E(R_m) - (R_f)]$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**3.50%**	**0.55**	**5.75%**	**6.7%**
Hevert Proxy Group	**3.50%**	**0.55**	**5.75%**	**6.7%**

For the both the Electric and Hevert Proxy Groups, the risk-free rate of 3.50% plus the product of the beta of 0.55 times the equity risk premium of 5.75% results in a 6.7% equity cost rate.

Q. THESE CAPM EQUITY COST RATES SEEM LOW. WHY IS THAT?

A. One major factor is that the riskiness of utilities has declined in recent years, and this lower risk is reflected in their betas. Utility betas have been in the .70 to .75 range in recent years. But they have declined in the past year and are now are primarily in the 0.55 to 0.60 range.

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. My DCF analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 8.15% and 8.40%, respectively. The CAPM equity cost rates for both groups are 6.70%. Table 7, below, shows these results.

Table 7
ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	**8.15%**	**6.70%**
Hevert Proxy Group	**8.40%**	**6.70%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Hevert Proxy Groups is in the 6.90% to 8.40% range.

Q. WHAT EQUITY COST RATE ARE YOU RECOMMENDING FOR DEP?

A. Given these results, I am recommending an equity cost rate or ROE for DEP of 8.40%. I believe that this equity cost rate accurately reflects the market cost of equity capital when there last was equilibrium. As I previously noted, at that time, capital costs in the U.S. remained low, with low inflation and interest rates, very modest economic growth, and the stock market was at an all-time high. I believe that this range accurately reflects capital market data at this time of equilibrium. However, given that I am recommending a capital structure with a lower common equity ratio and higher financial risk than proposed by the Company, as a primary ROE for DEP, I am recommending 9.0%. Therefore, as a primary ROE for DEP, I am recommending 9.0%. This recommendation gives weight to the risk associated with the lower common equity ratio.

Q. PLEASE INDICATE WHY YOUR EQUITY COST RATE RECOMMENDATIONS OF 9.0%/8.40% ARE APPROPRIATE FOR DEP.

A. There are a number of reasons why an equity cost rate of 9.0%/8.40% is appropriate and fair for the Company in this case:

1. DEP's investment risk, as indicated by its S&P and Moody's credit ratings of A- and A2, is below the averages of the Electric and Hevert Proxy Groups;

2. As shown in Exhibits JRW-5, capital costs for utilities, as indicated by long-term utility bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time;

3. As shown in Exhibit JRW-5, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. Most notably, the betas for electric utilities have been declining in recent years, which indicates the risk of the industry has declined. Overall, the cost of equity capital for this industry is the lowest in the U.S., according to the CAPM;

4. I have recommended an equity cost rate at the high end of the range of my ROE outcomes;

5. As shown in Figure 3, the authorized ROEs for electric utility and gas distribution companies have declined in recent years. On an annual basis, these authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.64% in of 2019, according to Regulatory Research

Associates.[48] In my opinion, these authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. However, the trend has been towards lower ROEs, and the norm now is below ten percent. Hence, I believe that my recommended ROE reflects the low capital cost rates in today's markets, and these low capital cost rates are finally being recognized by state utility commissions.

VI. CRITIQUE OF DEP'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE THE COMPANY'S COST OF EQUITY CAPITAL RECOMMENDATION.

A. The Company has proposed a hypothetical capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.15%. Mr. Hevert has recommended a common equity cost rate of 10.50%. The Company's overall proposed rate of return is 7.52%.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF EQUITY CAPITAL POSITION?

A. I have a number of issues with the Company's ROE position:

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[48] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2019.

Capital Structure – The Company has proposed a hypothetical capital structure consisting of 47.00% long-term debt and 53.00% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups as well as DEP and DEP's parent, Duke Energy. In my primary rate of return recommendation, I recommend adjusting DEP's proposed capital structure to use a common equity component of 50 percent, as that is more in line with the capital structures of the utilities in both proxy groups as well as DEP's parent, Duke Energy. In my alternative rate of return recommendation, I use DEP's actual capital structure as of December 31, 2019, which includes a common equity ratio of 51.5%. In this case, I employ a lower ROE to reflect the higher common equity component in the capital structure and lower financial risk of the Company's actual capitalization.

Embedded Cost of Debt – The Company proposes to use as its embedded cost of long-term debt its rate as of December 31, 2018. Since that time, its debt costs have come down four basis points, and it is appropriate and fair to ratepayers that a more current cost of long-term debt be used.

Capital Market Conditions – Mr. Hevert's analyses, ROE results, and recommendations reflect an assumption of higher interest rates and capital costs that is inconsistent with current trends. Despite the Federal Reserve's moves to increase the federal funds rate over the 2015-18 time period, interest rates and capital costs remained at low levels. In 2019, interest rates fell dramatically with slow economic growth and low inflation. The Federal Reserve cut the federal fund rate three times in July, September, and October, and the 30-year yield traded at all-time low levels. In 2020, interest rates have again fallen to record low levels, with investors being very concerned over the impact of the coronavirus. In response, the Federal Reserve cut the federal fund rate by 50 basis points on March 3rd, and then another 50 basis points on March 15th. This issue is addressed in Appendix B.

The Company's ROE Analysis is Out-of-Date - The Company's ROE study was prepared in August, 2019, about eight months ago. Since that time, the Federal Reserve has cut the federal funds rate three times and the 30-year Treasury rate has fallen over 70 basis points. Capital costs are much lower now not only than when the Company's ROE study was prepared, but also when it filed its request to increase rates.

DEP's Investment Risk is Below the Averages of the Two Proxy Groups – Mr. Hevert cites the Company's capital expenditures and North Carolina's regulatory environment to imply that DEP is riskier than his proxy group. However, his assessment of DEP's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DEP's S&P and Moody's credit rating suggest that the Company's investment risk is below the averages of the proxy groups.

Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.50% ROE Recommendation – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.50% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.50% are some of his CAPM/ECAPM results, which as I explain later in my testimony are seriously flawed. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) and primarily from *Value Line* data. Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.50% ROE recommendation.

DCF Equity Cost Rate - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. There are several errors regarding Mr. Hevert's DCF analyses: (1) he has given very little weight to his constant-growth DCF results; (2) He has claimed that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields; and (3) he has relied exclusively on the overly optimistic and upwardly biased EPS growth-rate forecasts of Wall Street analysts and *Value Line.*

<u>CAPM Approach</u> - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are two primary issues with Mr. Hevert's CAPM analyses: (1) he has employed an ad hoc version of the CAPM, ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research; and (2) his market risk premiums of 12.05% and 12.19% are exaggerated and do not reflect current market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and market risk premium. These EPS growth-rate projections and the resulting expected market returns and market risk premiums include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

<u>Alternative Risk Premium Model</u> - Mr. Hevert estimates an equity cost rate using an alternative risk premium model which he calls the BYRP approach. The risk premium in his BYRP method is based on

the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach including: (1) this approach is a gauge of commission behavior and not investor behavior; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium because his approach uses historical authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields; and (3) the risk premium is inflated as a measure of investor's required risk premium, because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

<u>Expected Earnings Approach</u> - Mr. Hevert also uses the Expected Earnings approach to estimate an equity cost rate for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group as well as for *Value Line*'s universe of electric utilities. The biggest issue is that the so-called "Expected Earnings" approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's "Expected Earnings" approach in determining the appropriate ROE for DEP.

Other Issues - Mr. Hevert also considers several other factors in arriving at his 10.50% ROE recommendation. Mr. Hevert has cited North Carolina's environmental regulations, in particular those relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering. However, these are risk factors already considered in the credit-rating process used by major rating agencies. As I noted above, DEP's investment risk as measured by S&P and Moody's is below the average of the proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE recommendation of 10.50%. However, he has not identified any future flotation costs for DEP.

North Carolina Economic Conditions – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DEP's proposed ROE of 10.50% is fair and reasonable to DEP, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree that prior to the coronavirus, economic conditions had improved in North Carolina, the improvements do not necessarily justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DEP's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-20 time period; (2) while the unemployment rates in North Carolina and DEP's service territory had fallen since their peaks in the 2009-2010 period, the unemployment rates in North Carolina (4.20%) and DEP's Service territory (4.87%) prior to the coronavirus were both well above the national average (3.70%); and (3) while North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

Capital market conditions, the out-of-date ROE study, DEP's proposed capital structure, DEP's proposed embedded cost of long-term debt, and the investment risk of DEP were previously discussed. The other issues are addressed below.

A. The Disconnect Between Mr. Hevert's Equity Cost Rate Results and His 10.50% ROE Recommendation

Q. PLEASE REVIEW MR. HEVERT'S EQUITY COST RATE RESULTS AND HIS 10.50% ROE RECOMMENDATION.

A. Page 1 of Exhibit JRW-9 shows Mr. Hevert's equity cost rate results using the DCF, CAPM, and BYRP approaches. There appears to be a disconnect between these results and his 10.50% ROE recommendation. First, it is very difficult to see exactly how he gets to his 10.50% ROE recommendation. He provides no details on how he weighted his equity cost rate results to get to 10.50%.

Second, the vast majority of his equity cost rate results point to a lower ROE. The average of his DCF results is 8.86%, to which he clearly gave no weight. His BYRP results, which are inflated because he has used projected interest rates, average 9.96%. His CAPM results, calculated using data from Bloomberg and *Value Line*, range from 8.44% to 9.62%. These results clearly do not support a ROE of 10.50%.

Finally, the only results that point to a ROE as high as 10.50% are his ECAPM results using *Value Line* betas. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one ad hoc CAPM model (the ECAPM); and, even more narrowly, (2) only one source of financial information for betas (*Value Line*). In addition, as discussed below, there are a number of empirical issues with the *Value Line* projected EPS growth rates which result in an overstated expected market return and market risk premium. Otherwise, Mr. Hevert provides no other credible equity cost rate studies that support his 10.50% ROE recommendation. Therefore, his ROE recommendation is based on not only one model (ECAPM), but also on only one information source (*Value Line*). There are obvious risks to relying on only one approach and information source to estimate the cost of equity capital.

B. DCF Approach

Q. PLEASE SUMMARIZE MR. HEVERT'S DCF ESTIMATES.

A. On pages 78-84 of his testimony and in Exhibit No. RBH-1, Mr. Hevert develops an equity cost rate by applying the DCF model to the Hevert Proxy Group. Mr. Hevert's DCF results are summarized on page 2 of my Exhibit JRW-9. He uses a constant-growth growth DCF models. Mr. Hevert uses three dividend-yield measures (30, 90, and 180 days) in his DCF models. In his constant-growth and quarterly DCF models, Mr. Hevert has relied on the forecasted EPS growth rates of Zacks, First Call, and *Value Line*. For each model, his mean DCF results range from 8.78% to 8.97%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S DCF ANALYSES?

A. The primary errors in Mr. Hevert's DCF analyses are: (1) the low weight he gives to his constant-growth DCF results, and (2) his exclusive use of the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line.*

1. The Low Weight Given to the DCF Results

Q. HOW MUCH WEIGHT HAS MR. HEVERT GIVEN HIS DCF RESULTS IN ARRIVING AT AN EQUITY COST RATE FOR THE COMPANY?

A. Apparently, very little, if any. The average of his mean constant-growth DCF equity cost rates is only 8.86%. Had he given these results any weight, he would have arrived at a much lower recommendation for his estimated cost of equity.

2. The DCF Model Understates the Cost of Equity Capital

Q. PLEASE EXPLAIN MR. HEVERT'S CLAIM THAT THE DCF MODEL UNDERSTATES THE COST OF EQUITY CAPITAL.

A. At pages 5-10 of his testimony, Mr. Hevert expresses concern with the constant-growth DCF model results in light of capital market conditions, which include high utility stock valuations and low dividend yields. However, Mr. Hevert's arguments on this issue are without merit for the following reasons: (1) he is saying that utility stocks are overvalued, and their stock prices will decline in the future (and therefore their dividend yield will increase). Hence, Mr. Hevert presumes that he knows more than investors in the stock market. If he believes that utility stock prices will decline in the future, he should be recommending a negative expected return because a decline in utility stock prices would produce negative stock returns in the future; (2) the DCF approach directly measures the cost of equity because it uses dividends, stock prices, and expected growth rates; (3) the CAPM is an indirect method of measuring the cost of equity with the only company-specific input being beta. In addition, it is highly dependent on the market risk premium which, as discussed above, is one of the great mysteries in finance; and (4) as discussed below, Mr. Hevert's CAPM results are grossly inflated due to its unrealistic assumptions on future earnings, economic growth, and future stock returns.

Q. ARE THERE OTHER REASONS WHY UTILITY STOCK STOCKS HAVE PERFORMED SO WELL AND HAVE RELATIVELY HIGH VALUATIONS?

A. Yes. As discussed in a Moody's article, utilities have achieved higher market valuations due to cost recovery mechanisms that have reduced the risk of the utility industry, which have led to higher valuation levels.

> As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower

> authorized returns, although because utilities will argue they should rise, or at least stay unchanged.[49]

Therefore, Mr. Hevert's suggestion that the constant-growth DCF results provide low equity cost rate results due to current market conditions is incorrect. As indicated by Moody's, the lower risk of utilities has led to higher valuation levels.

3. Wall Street Analysts' EPS Growth Rate Forecasts

Q. PLEASE DISCUSS MR. HEVERT'S EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE* FOR HIS DCF ANALYSIS.

A. It seems highly unlikely that investors today would rely exclusively on the EPS growth rate forecasts of Wall Street analysts and ignore other growth rate measure in arriving at their expected growth rates for equity investments. As I previously stated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth.

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[49] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015, p. 3.

Finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. In addition, as discussed above, the projected EPS growth rate forecasts have been shown to be overly-optimistic and upwardly biased.

Hence, using these growth rates as a DCF growth rate produces an overstated equity cost rate. A 2007 study by Easton and Sommers found that optimism in analysts' earnings growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[50]

Q. ON PAGES 81-82 OF HIS TESTIMONY, MR. HEVERT CITES NINE DIFFERENT STUDIES TO SUPPORT HIS USE OF ANALYSTS' EPS GROWTH RATE FORECASTS. PLEASE DISCUSS THESE STUDIES.

A. The studies Mr. Hevert cites to support his exclusive use of analysts' EPS growth rate forecasts are all at least 20 years old. There have been many research studies on this topic over the past 20 years. I reviewed these studies earlier in my testimony. The conclusion from

[50] Easton, P., & Sommers, G. (2007). "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts." *Journal of Accounting Research*, 45(5), 983–1015.

the more recent studies is universal – analysts' three-to-five-year EPS growth rate forecasts are overly optimistic and upwardly biased.

C. CAPM Approach

Q. PLEASE DISCUSS MR. HEVERT'S CAPM.

A. On pages 87-96 of his testimony and in Exhibit Nos. RBH-2-RBH-4, Mr. Hevert develops an equity cost rate by applying the CAPM model to the companies in his proxy group. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the market risk premium. Mr. Hevert uses two different measures of the 30-Year Treasury bond yield: (a) current yield of 2.43% and a near-term projected yield of 2.65%; (b) two different betas (an average Bloomberg beta of 0.499 and an average *Value Line* beta of 0.57); and (c) two market risk premium measures – a Bloomberg, DCF-derived market risk premium of 12.05% and a *Value Line* DCF-derived market risk premium of 12.19%. Based on these figures, he finds a CAPM equity cost rate range from 8.44% to 9.62%. Mr. Hevert also employs an ad hoc version of the CAPM, the ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and professional research. His ECAPM results range from 9.95% to 10.93%. Mr. Hevert's CAPM/ECAPM results are summarized on page 2 of Exhibit JRW-9.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S CAPM ANALYSES?

A. As explained further below, there are two issues with Mr. Hevert's CAPM analyses: (1) Mr. Hevert has employed an ad hoc version of the CAPM, the ECAPM; and (2) Mr. Hevert's market risk premiums of 12.05% and 12.19% include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

1. Market Risk Premiums

Q. PLEASE ASSESS MR. HEVERT'S MARKET RISK PREMIUMS DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500 AND *VALUE LINE INVESTMENT SURVEY*.

A. Table 8 provides the details of Mr. Hevert's computations of his Bloomberg and *Value Line* market risk premiums, of 12.05% and 12.19%, respectively. Mr. Hevert: (1) calculates an expected market return by applying the DCF model to the S&P 500; and then (2) subtracted the current 30-year Treasury bond yield of 2.43% from his estimate of the expected market return. Mr. Hevert also uses (1) a dividend yield of 1.98% and an expected DCF growth rate of 12.50% for Bloomberg; and (2) a dividend yield of 2.09% and an expected DCF growth rate of 12.53% for *Value Line.* Mr. Hevert's approach suggests that annual stock-market returns for the S&P 500 companies are 14.48% (using Bloomberg three-to-five-year EPS growth rate estimates) and 14.62% (using *Value Line's* five-year

EPS growth rate estimates). As discussed below, these expected EPS growth rates and expected stock market returns and market risk premiums are totally unrealistic.

Table 8
Market Risk Premiums Derived from Expected Market Returns Using *Value Line* and Bloomberg Projected EPS Growth Rate

	BL DCF Exp. Ret.	VL DCF Exp. Ret.
Dividend Yield	1.98%	2.09%
+ Expected EPS Growth	12.50%	12.53%
= Expected Market Return	14.48%	14.62%
- Risk-Free Rate	2.43%	2.43%
= Market Risk Premium	12.05%	12.19%

Q. ARE MR. HEVERT'S MARKET RISK PREMIUMS OF 12.05% AND 12.19% REFLECTIVE OF THE MARKET RISK PREMIUMS FOUND IN STUDIES AND SURVEYS OF THE MARKET RISK PREMIUM?

A. No. These are well in excess of market risk premiums: (1) found in studies of the market risk premium by leading academic scholars; (2) produced by analyses of historic stock and bond returns; and (3) found in surveys of financial professionals. Page 5 of Exhibit JRW-8 provides the results of over 30 market risk premium studies from the past 15 years. Historic stock and bond returns suggest a market risk premium in the 4.5% to 7.0% range, depending on whether one uses arithmetic or geometric mean returns. There have been many studies using expected return (also called *ex ante*) models, and their market risk premium results vary from as low as 2.0% to as high as 7.31%. Finally, the market risk premiums developed from surveys of analysts, companies, financial professionals, and academics suggest lower market risk premiums, in a range of from 1.91% to 5.70%. The bottom line is that there is no support in historic return data, surveys, academic studies, or reports for investment firms for market risk premiums as high as those used by Mr. Hevert.

Q. PLEASE AGAIN ADDRESS THE ISSUES WITH ANALYSTS' EPS GROWTH RATE FORECASTS.

A. The key point is that Mr. Hevert's CAPM market risk premium methodology is based entirely on the concept that analyst projections of companies' three-to-five EPS growth rates reflect investors' expected *long-term* EPS growth for those companies. However, this seems highly unrealistic given the research on these projections. As previously noted, numerous studies have shown that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[51] Moreover, a 2011 study

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[51] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance,* pp. 643−684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and*

showed that analysts' forecasts of EPS growth over the next three-to-five years earnings are no more accurate than their forecasts of the next single year's EPS growth.[52] The overly-optimistic inaccuracy of analysts' growth rate forecasts leads to an upward bias in equity cost estimates that has been estimated at about 300 basis points.[53]

Q. HAVE CHANGES IN REGULATIONS IMPACTED THE UPWARD BIAS IN WALL STREET ANALYSTS' THREE-TO-FIVE YEAR EPS GROWTH RATE FORECASTS?

A. No. A number of the studies I have cited here demonstrate that the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is highlighted by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy of analysts' long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings

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Management Forecasting (Vol. 8), Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[52] M. Lacina, B. Lee, & Z. Xu, *Advances in Business and Management Forecasting,* Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[53] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

forecasts continue to be excessively optimistic. They made the following observation:[54]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*

This is the same observation made in a *Bloomberg Businessweek* article.[55] The author concluded:

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[54] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010) (emphasis added).

[55] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek* (June 10, 2010), https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. IS THERE OTHER EVIDENCE THAT INDICATES THAT MR. HEVERT'S MARKET RISK PREMIUMS COMPUTED USING S&P 500 EPS GROWTH RATE ARE EXCESSIVE?

A. Beyond my previous discussion of the upwardly biased nature of analysts' projected EPS growth rates, the fact is that long-term EPS growth rates of 12.50% and 12.53% are inconsistent with both historic and projected economic and earnings growth in the U.S. for several reasons: (1) long-term EPS and economic growth is about one-half of Mr. Hevert's projected EPS growth rates of 12.50% and 12.53%; (2) as discussed below, long-term EPS and Gross Domestic Product (GDP) growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future.

<u>Long-Term Historic EPS and GDP Growth have been in the 6%-7% Range</u> - I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-10, and a summary is shown in Table 9, below.

Table 9
GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	6.46
S&P 500 Stock Price	6.71
S&P 500 EPS	6.89
S&P 500 DPS	5.85
Average	6.48

The results show that the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 6% to 7% range. By comparison, Mr. Hevert's long-run growth rate projections of 12.50% and 12.53% are at best overstated. For Mr. Hevert's estimates to come to fruition, companies in the U.S. would be expected to: (1) increase their growth rate of EPS by 100% in the future, and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-third of his projected growth rates.

There is a Direct Link Between Long-Term EPS and GDP Growth - The results in Exhibit JRW-10 and Table 9 show that historically there has been a close link between long-term EPS and GDP growth rates. Brad Cornell of the California Institute of Technology published a study on GDP growth, earnings growth, and equity returns. He found that long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he found that long-term stock returns are determined by long-term earnings growth. He concluded with the following observations:[56]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

<u>The Trend and Projections Indicate Slower GDP Growth in the Future</u> - The components of nominal GDP growth are real GDP growth and inflation. Page 3 of Exhibit JRW-10 shows annual real GDP growth rate over the 1961 to 2018 time period. Real GDP growth has gradually declined from the 5.0% to 6.0% range in the 1960s to the 2.0% to 3.0% range during the most recent five-year period. The second component of nominal GDP growth is inflation. Page 4 of Exhibit JRW-10 shows inflation as measured by the annual growth rate in the Consumer Price Index (CPI) over the 1961 to 2018 time period. The large increase in prices from the late 1960s to the

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[56] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February 2010), p. 63.

early 1980s is readily evident. Equally evident is the rapid decline in inflation during the 1980s as inflation declined from above 10% to about 4%. Since that time, inflation has gradually declined and has been in the 2.0% range or below over the past five years.

The graphs on pages 2, 3, and 4 of Exhibit JRW-10 provide clear evidence of the decline, in recent decades, in nominal GDP as well as its components, real GDP and inflation. To gauge the magnitude of the decline in nominal GDP growth, Table 5, below, provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50- years.[57] Whereas the 50-year compounded GDP growth rate is 6.63%, there has been a monotonic and significant decline in nominal GDP growth over subsequent t-year intervals. These figures strongly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy.

[57] Table 5 is also included as Page 5 of Exhibit JRW-10.

Table 10
Historical Nominal GDP Growth Rates

10-Year Average		**3.37%**
20-Year Average		**4.17%**
30-Year Average		**4.65%**
40-Year Average		**5.56%**
50-Year Average		**6.36%**

Long-Term GDP Projections also Indicate Slower GDP Growth in the Future - A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of on page 5 of Exhibit JRW-10. The mean 10-year nominal GDP growth forecast (as of March 2019) by economists in the recent *Survey of Financial Forecasters* is 4.25%.[58] The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook,* forecasts long-term GDP growth of 4.20% for the period 2018-2050.[59] The Congressional Budget Office (CBO), in its forecasts for the period 2019 to 2049, projects a nominal GDP growth rate of 4.40%.[60] Finally, the Social Security Administration (SSA), in its Annual OASDI Report, provides a projection of nominal

[58] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/

[59] U.S. Energy Information Administration, *Annual Energy Outlook 2019*, Table: Macroeconomic Indicators, https://www.eia.gov/outlooks/aeo/pdf/appa.pdf.

[60] Congressional Budget Office, The *2019 Long-Term Budget Outlook*, June 15, 2019 https://www.eia.gov/outlooks/aeo/pdf/appa.pdf.

GDP from 2018-2095.[61] SSA's projected growth GDP growth rate over this period is 4.35%. Overall, these forecasts suggest long-term GDP growth rate in the 4.20% - 4.4% range. The trends and projections indicating slower GDP growth make Mr. Hevert's market risk premiums computed using analysts' projected EPS growth rates look even more unrealistic. Simply stated, Mr. Hevert's projected EPS growth rates of 12.50% and 12.53% are almost three times projected GDP growth.

Q. WHAT ARE THE FUNDAMENTAL FACTORS THAT HAVE LED TO THE DECLINE IN PROSPECTIVE GDP GROWTH?

A. As addressed in a study by the consulting firm McKinsey & Co., two factors drive real GDP growth over time: (a) the number of workers in the economy (employment); and (2) the productivity of those workers (usually defined as output per hour).[62] According to McKinsey, real GDP growth over the past 50 years was driven by population and productivity growth, which grew at compound annual rates of 1.7% and 1.8%, respectively.

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[61] Social Security Administration, *2019 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program*, Table VI.G4, p. 211 (June 15, 2019), https://www.ssa.gov/oact/TR/2019/VI_G2_OASDHI_GDP.html#200732. The 4.35% represents the compounded growth rate in projected GDP from $21,485 trillion in 2019 to $546,311 trillion in 2095.

[62] McKinsey & Co., "Can Long-Term Growth be Saved?", McKinsey Global Institute, (Jan. 2015).

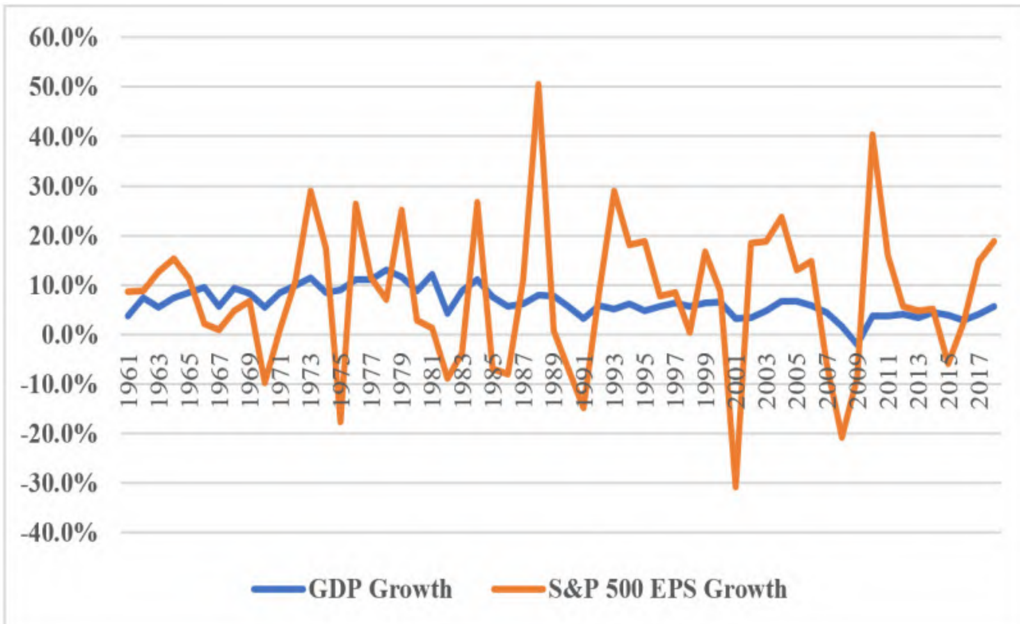
However, global economic growth is projected to slow significantly in the years to come. The primary factor leading to the decline is slow growth in employment (working-age population), which results from slower population growth and longer life expectancy. McKinsey estimates that employment growth will slow to 0.3% over the next 50 years. The study concludes that even if productivity remains at the rapid rate of the past 50 years of 1.8%, real GDP growth will fall by 40% to 2.1%.

Q. PLEASE PROVIDE MORE INSIGHTS INTO THE RELATIONSHIP BETWEEN S&P 500 EPS AND GDP GROWTH.

A. Figure 7 shows the average annual growth rates for GDP and the S&P 500 EPS since 1960. The one very apparent difference between the two is that the S&P 500 EPS growth rates are much more volatile than the GDP growth rates, when compared using the relatively short, and somewhat arbitrary, annual conventions used in these data.[63] Volatility aside, however, it is clear that over the medium to long run, S&P 500 EPS growth does not outpace GDP growth.

[63] Timing conventions such as years and quarters are needed for measurement and benchmarking but are somewhat arbitrary. In reality, economic growth and profit accrual occur on continuous bases. A 2014 study evaluated the timing relationship between corporate profits and nominal GDP growth. The authors found that aggregate accounting earnings growth is a leading indicator of the GDP growth with a quarter-ahead forecast horizon. *See* Yaniv Konchitchki and Panos N. Patatoukas, "Accounting Earnings and Gross Domestic Product," *Journal of Accounting and Economics* 57 (2014), pp. 76–88.

Figure 7
Average Annual Growth Rates
GDP and S&P 500 EPS
1960-2018



Data Sources: GDPA -
http://research.stlouisfed.org/fred2/series/GDPA/downloaddata.
S&P EPS - http://pages.stern.nyu.edu/~adamodar/

A fuller understanding of the relationship between GDP and S&P 500 EPS growth requires consideration of several other factors.

Corporate Profits are Constrained by GDP – Milton Friedman, the noted economist, warned investors and others not to expect corporate profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[64] Friedman also noted in the *Fortune* interview that profits must move back down to their traditional share of GDP. In Table 11, below, I show that the aggregate net income levels for the S&P 500 companies, using 2018 figures, represent 6.73% of nominal GDP.

Table 11

S&P 500 Aggregate Net Income as a Percent of GDP

Aggregate Net Income for S&P 500 Companies ($B)	**$1,406,400.00**
2018 Nominal U.S. GDP ($B)	**$20,891,000.00**
Net Income/GDP (%)	**6.73%**

Data Sources: 2018 Net Income for S&P 500 companies – Value Line (March 12, 2019). 2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.

Short-Term Factors Impact S&P 500 EPS – The growth rates in the S&P 500 EPS and GDP can diverge on a year-to-year basis due to short-term factors that impact S&P 500 EPS in a much greater way than GDP. As shown above, S&P EPS growth rates are much more volatile than GDP growth rates. The EPS growth for the S&P 500 companies has been influenced by low labor costs and interest rates, commodity prices, the recovery of different sectors such as the energy and financial sectors, the cut in corporate tax rates, etc.

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[64] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

These short-term factors can make it appear that there is a disconnect between the economy and corporate profits.

The Differences Between the S&P 500 EPS and GDP – In the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP.[65] These differences include: (a) corporate profits are about 2/3 manufacturing driven, while GDP is 2/3 services driven; (b) consumer discretionary spending accounts for a smaller share of S&P 500 profits (15%) than of GDP (23%); (c) corporate profits are more international-trade driven, while exports minus imports tend to be a drag on GDP; and (d) S&P 500 EPS is impacted, not just by corporate profits, but also by share buybacks on the positive side (fewer shares boost EPS) and by share dilution on the negative side (new shares dilute EPS). While these differences may seem significant, it must be remembered that the Income Approach to measure GDP includes corporate profits (in addition to employee compensation and taxes on production and

[65] *See* the following studies: Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," LPL Financial, (Nov. 4, 2014), https://www.businessinsider.com/sp-is-not-gdp-2014-11; Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?," Seeking Alpha, (Apr. 2018), https://seekingalpha.com/article/4164052-18_4-percent-earnings-growth-2_58-percent-gdp-economy; Shaun Tully, "How on Earth Can Profits Grow at 10% in a 2% Economy?," Fortune, (July 27, 2017), http://fortune.com/2017/07/27/profits-economic-growth/.

imports) and therefore effectively accounts for the first three factors.[66]

The bottom line is that despite the intertemporal short-term differences between S&P 500 EPS and nominal GDP growth, the long-term link between corporate profits and GDP is inevitable.

Q. PLEASE PROVIDE ADDITIONAL EVIDENCE ON HOW UNREALISTIC THE S&P 500 EPS GROWTH RATES ARE THAT MR. HEVERT USES TO COMPUTE HIS MARKET RISK PREMIUMS.

A. Beyond my previous discussion, I have performed the following analysis of S&P 500 EPS and GDP growth in Table 12 below. Specifically, I started with the 2018 aggregate net income for the S&P 500 companies and 2018 nominal GDP for the U.S. As shown in Table 11, the aggregate profit for the S&P 500 companies represented 6.73% of nominal GDP in 2018. In Table 12, I then projected the aggregate net income level for the S&P 500 companies and GDP as of the year 2050. For the growth rate for the S&P 500 companies, I used the average of Mr. Hevert's Bloomberg and *Value Line* growth rates, 12.50% and 12.53%, which is 12.52. As a growth

[66] The Income Approach to measuring GDP includes wages, salaries, and supplementary labor income, corporate profits, interest and miscellaneous investment income, farmers' incomes, and income from non-farm unincorporated businesses.

rate for nominal GDP, I used the average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.40%, 4.35%, and 4.20%), which is 4.32%. The projected 2050 level for the aggregate net income level for the S&P 500 companies is $64.3 trillion. However, over the same period GDP only grows to $80.8 trillion. As such, if the aggregate net income for the S&P 500 grows in accordance with the growth rates used by Mr. Hevert, and if nominal GDP grows at rates projected by major government agencies, the net income of the S&P 500 companies will represent growth from 6.73% of GDP in 2018 to 75.78% of GDP in 2050. Obviously, it is implausible for the net income of the S&P 500 to become such a large part of GDP.

Table 12
Projected S&P 500 Earnings and Nominal GDP
2018-2050
S&P 500 Aggregate Net Income as a Percent of GDP

	2018 Value	Growth Rate	No. of Years	2050 Value
Aggregate Net Income for S&P 500	**1,406,400.0**	**12.52%**	**32**	**61,212,827.7**
2018 Nominal U.S. GDP	**20,891,000.0**	**4.32%**	**32**	**80,775,130.2**
Net Income/GDP (%)	**6.73%**			**75.78%**

Data Sources: 2018 Aggregate Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.
S&P 500 EPS Growth Rate - Average of Hevert's Bloomberg and *Value Line* growth rates - 12.50% and 12.53% = 12.52%;
Nominal GDP Growth Rate – The average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.40%, 4.35%, and 4.20% = 4.32%).

Q. PLEASE PROVIDE A SUMMARY ANALYSIS ON GDP AND S&P 500 EPS GROWTH RATES.

A. As noted above, the long-term link between corporate profits and GDP is inevitable. The short-term differences in growth between the two has been highlighted by some notable market observers, including Warren Buffett, who indicated that corporate profits as a share of GDP tend to go far higher after periods where they are depressed, and then drop sharply after they have been hovering at historically high levels. In a famous 1999 *Fortune* article, Mr. Buffet made the following observation:[67]

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%. One thing keeping the percentage down will be competition, which is alive and well. In addition, there's a public-policy point: If corporate investors, in aggregate, are going to eat an ever-growing portion of the American economic pie, some other group will have to settle for a smaller portion. That would justifiably raise political problems – and in my view a major reslicing of the pie just isn't going to happen.

In sum, Mr. Hevert's long-term S&P 500 EPS growth rates of 12.50% and 12.53% are grossly overstated and have no basis in economic

[67] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, (Nov. 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

reality. In the end, the big question remains as to whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0%, due to the big gains in the technology sector. But he also believes that sustained EPS growth matching analysts' near-term projections is absurd: "The idea of 8% or 10% or 12% growth is ridiculous. It will not happen."[68]

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE CAPM RESULTS.

A. There are several additional issues with the *Value Line* results. Simply put, the 14.48% and 14.62% expected stock market returns (Mr. Hevert's Exhibit RBH-2 at pages 1 and 8) are simply excessive. The compounded annual return in the U.S. stock market is about 10% (9.71% between 1928-2019 according to Damodaran).[69] Mr. Hevert's *Value Line* CAPM results assume that return on the U.S. stock market will be almost 50% higher in the future than it has been in the past! The extremely high expected stock market returns, and

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[68] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

[69] http://pages.stern.nyu.edu/~adamodar/

their resulting market risk premiums and equity cost rate results, are directly related to the 12.05% and 12.19% expected EPS growth rates. Simply put, these projected growth rates do not reflect economic reality. As noted above, it assumes that S&P 500 companies can grow their earnings in the future at a rate that is triple the expected GDP growth rate.

2. ECAPM

Q. WHAT ISSUES DO YOU HAVE WITH MR. HEVERT'S ECAPM?

A. Mr. Hevert has employed a variation of the CAPM which he calls the "ECAPM". The ECAPM, as popularized by rate of return consultant Dr. Roger Morin, attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line ("SML") is not as steep as predicted by the CAPM.[70] As such, the ECAPM is nothing more than an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. The ECAPM uses weighting to adjust the risk-free rate and market risk premium in applying the ECAPM. Mr. Hevert uses 0.25 and 0.75 factors in his ECAPM.

[70] In Modern Capital Market theory, the SML is the relationship between the expected return on common stocks and beta.

Besides the fact that the ECAPM is not a recognized equity cost rate model, Mr. Hevert has already accounted for any empirical issues with the CAPM by using adjusted betas from *Value Line*. Adjusted betas address the empirical issues with the CAPM by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks.

D. Bond Yield Risk Premium Approach

Q. PLEASE DISCUSS MR. HEVERT'S BYRP APPROACH.

A. On pages 96-100 of his testimony and in Exhibit No. RBH-5, Mr. Hevert develops an equity cost rate using his BYRP approach. Mr. Hevert develops an equity cost rate by: (1) regressing the average quarterly authorized returns on equity for electric utility companies from the January 1, 1992, to July 31, 2019, time period on the 30-year Treasury Yield; and (2) adding the appropriate risk premium established in step (1) to three different 30-year Treasury yields: (a) the current yield of 2.43%; (b) a near-term projected yield of 2.65%; and (c) a long-term projected yield of 3.70%. Mr. Hevert's risk premium results are provided on Exhibit JRW-9. He reports BYRP equity cost rates ranging from 9.91% to 10.06%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S BYRP ANALYSIS?

A. The errors include the base yield as well as the measurement and magnitude of the risk premium.

1. Base Yields

Q. PLEASE DISCUSS THE BASE YIELD OF MR. HEVERT'S BYRP ANALYSIS.

A. Mr. Hevert has used current, near-term projected, and long-term projected risk-free rates of 2.63%, 2.70%, and 3.70% in his BYRP analyses. The actual yield on 30-year Treasury bonds has been in the 1.60% range in recent months. As such, Mr. Hevert's current, near-term projected, and long-term projected risk-free rates are 97, 104, and 210 basis points, respectively, above the current yield on long-term Treasury bonds. These current and forecasted yields are excessive for two reasons. First, as discussed previously, economists have been predicting that interest rates are going up for a decade, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore are likely to place little weight on such forecasts. Second, investors would not be buying long-term Treasury bonds at their current yields if they expected interest rates to suddenly increase. If interest rates do increase, the prices of the bonds investors bought at today's yields go down, thereby producing a negative return.

2. Risk Premium

Q. WHAT ARE THE ISSUES WITH MR. HEVERT'S RISK PREMIUM?

A. There are several problems with his approach. First, his BYRP methodology produces an inflated measure of the risk premium because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if calculated correctly, which would be to use projected Treasury yields in the analysis rather than historic Treasury yields.

In addition, Mr. Hevert's BYRP approach is a gauge of *commission* behavior and not *investor* behavior. Capital costs are determined in the marketplace through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also consider other utility- and rate case-specific information in setting ROEs. As such, Mr. Hevert's approach and results reflect factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This may especially be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated.

Finally, Mr. Hevert's methodology produces an inflated required rate of return because utilities have been selling at market-to-book ratios well in excess of 1.0 for many years. This indicates that the authorized and earned rates of return on equity have been greater than the return that investors require. The relationship between ROE, the equity cost rate, and market-to-book ratios was explained earlier in this testimony. In short, a market-to-book ratio above 1.0 indicates a company's ROE is above its equity cost rate. Therefore, the risk premium produced from the study is overstated as a measure of investor return requirements and produces an inflated equity cost rate.

E. Expected Earnings Approach

Q. PLEASE REVIEW MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. On pages 100-01 of his testimony and in Exhibit RBH-6, Mr. Hevert develops an equity cost rate using his Expected Earnings approach, which he uses for comparison purposes. Mr. Hevert's approach involves using *Value Line*'s projected ROE for the years 2022-24 for his proxy group and then adjusting this ROE to account for the fact the *Value Line* uses year-end equity in computing ROE. Mr. Hevert reports Expected Earnings results of 10.47% and 10.54%.

Q. PLEASE ADDRESS THE ISSUES WITH MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. There are a number of issues with this so-called Expected Earnings approach. As such, I strongly suggest that the Commission ignore this approach in setting a ROE for DEP. These issues include:

The Expected Earnings Approach Does Not Measure the Market Cost of Equity Capital – First and foremost, this accounting-based methodology does not measure investor return requirements. As indicated by Professor Roger Morin, a long-term utility rate of return consultant, "More simply, the Comparable (Expected) Earnings standard ignores capital markets. If interest rates go up 2% for example, investor requirements and the cost of equity should increase commensurably, but if regulation is based on accounting returns, no immediate change in equity cost results."[71] As such, this method does not measure the market cost of equity because there is no way to assess whether the earnings are greater than or

[71] Roger Morin, *New Regulatory Finance* (2006), p. 293.

less than the earnings investors require, and therefore this approach does not measure the market cost of equity capital.

<u>The Expected ROEs are Not Related to Investors' Market-Priced Opportunities</u> – The ROE ratios are an accounting measure that do not measure investor return requirements. Investors had no opportunity to invest in the proxy companies at the accounting book value of equity. In other words, the equity's book value *to investors* is tied to market prices, which means that investors' required return on market-priced equity aligns with expected return on book equity only when the equity's market price and book value are aligned. Therefore, a market-based evaluation of the cost of equity to investors in the proxies requires an associated analysis of the proxies' market-to-book ("M/B") ratios.

<u>Changes in ROE Ratios do not Track Capital Market Conditions</u> - As also indicated by Morin, "The denominator of accounting return, book equity, is a historical cost-based concept, which is insensitive to changes in investor return requirements. Only stock market price is sensitive to a change in investor requirements. Investors can only

purchase new shares of common stock at current market prices and not at book value."[72]

<u>The Expected Earnings Approach is Circular</u> - The proxies' ROEs ratios are not determined by competitive market forces, but instead are largely the result of federal and state rate regulation, including the present proceeding.

<u>The Proxies' ROEs Reflect Earnings on Business Activities that are not Representative of DEP's Rate-Regulated Utility Activities</u> - The numerators of the proxy companies' ROEs include earnings from business activities that are riskier and produce more projected earnings per dollar of book investment than does regulated electric utility service. These include earnings from: (1) unregulated businesses, including merchant generation; (2) electric generation; and (3) international operations.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. In short, Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators and, as shown above, and has a number of

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[72] *Id.*

other empirical issues. Therefore, the Commission should ignore this approach in determining the appropriate ROE for DEP.

F. Other Issues

1. Other DEP Risk Factors

Q. PLEASE ADDRESS MR. HEVERT'S CONSIDERATION OF OTHER UNIQUE RISK FACTORS FACED BY DEP.

A. Mr. Hevert has a number of risk factors he considered in arriving at his 10.50% ROE recommendation. These include North Carolina's environmental regulations, in particular those relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering. However, these are risk factors already considered in the credit-rating process used by major rating agencies. In addition, as I noted above, DEP's S&P and Moody's credit ratings of A- and A1 suggest that the Company's investment risk is below the average of the proxy groups.

2. Flotation Costs

Q. PLEASE DISCUSS MR. HEVERT'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Hevert argues that a flotation cost adjustment is appropriate for DEP and he has considered flotation costs in arriving at his 10.50% ROE recommendation.

First and foremost, Mr. Hevert has not identified any expected flotation costs for DEP. Therefore, he is asking for higher revenues in the form of a higher ROE for expenses that he has not identified.

Second, in North Carolina flotation costs cannot be recovered unless the Company is expected to issue common stock.[73]

Third, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the investment of the existing shareholders. This is incorrect for several reasons:

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[73] In NC, flotation costs cannot lawfully be recovered when the Company does not expect to issue stock in the near future. In State ex rel. Utilities Com. v. Public Staff, 331 N.C. 215; 415 S.E.2d 354 (1992), the Court noted that:

> Prompted by the statement of Duke's chairman, Mr. Lee, that "the company's 'present expectation is that we will be back into the capital markets for new funds in about three to four years,'" the only evidence in the record on the probability of Duke's issuing new stock, we noted the record included no evidence that Duke would issue any new stock sooner than three or four years from the time of the hearing.

Id. at 219. The Court then ruled that,

> In light of the whole record on this issue, particularly the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

Id. at 221-222.

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.95X actually suggests that there should be a flotation cost reduction (and not an increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence,

when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per-share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Therefore, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, and who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the

Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining its cost of equity. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to its DCF equity cost rate.

VII. North Carolina Economic Conditions and DEP's Rate of Return Recommendation

Q. PLEASE DISCUSS MR. HEVERT'S CONSIDERATION OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert has acknowledged that the North Carolina Utilities Commission must balance the interests of investors and customers in setting the ROE. In addition, Mr. Hevert notes that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions.[74] On this issue, the ROE should be the minimum amount needed to meet the *Hope* and *Bluefield* standards. Finally, Mr. Hevert also highlights that the North Carolina Supreme Court has indicated that in retail utility service rate cases, the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility.[75]

With respect to this latter mandate, Mr. Hevert evaluates a number of factors such as employment and income levels and, based on his review of the data, comes to the conclusion that DEP's proposed ROE of 10.50 percent is fair and reasonable to DEP, its shareholders, and its customers in light of the effect of those changing economic conditions.[76]

Q. DO YOU AGREE WITH MR. HEVERT THAT ECONOMIC CONDITIONS IN NORTH CAROLINA HAVE IMPROVED OVER THE PAST DECADE?

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[74] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; *see also* DEC Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.")

[75] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 758 S.E.2d 635, 642 (2014) (Cooper II).

[76] Hevert Testimony, pp. 53-62.

A. Yes, prior to the coronavirus. As highlighted by the correlations between U.S. and North Carolina economic data, I agree with Mr. Hevert that economic conditions in North Carolina had improved with the overall economy over the past decade. But Mr. Hevert's testimony predates the coronavirus crisis, which is detrimentally affecting the economic conditions of DEP's customers, North Carolina's economy, and the national economy.

Q. DO YOU AGREE WITH MR. HEVERT'S CONCLUSION THAT THE IMPROVEMENT IN ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY JUSTIFY THE COMPANY'S PROPOSED RATE OF RETURN INCLUDING A 10.50% ROE?

A. No. Whereas economic conditions had improved in North Carolina, it does not necessarily justify such a high rate of return and ROE. I have three observations on Mr. Hevert's assessment of the economic conditions in North Carolina and DEP's service territory and its requested ROE:

(1) DEP's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period;

(2) while the unemployment rates in North Carolina and DEP's service territory had fallen since their peaks in the 2009-2010 period, the unemployment rates in North Carolina (4.20%) and DEP's Service territory (4.87%) as of mid-2019 are both well above the national average (3.70%). In addition, unemployment is likely to increase as a result of the coronavirus; and

(3) whereas North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm. In addition, household income is likely to decline as a result of the coronavirus

Q. WHAT IS YOUR CONCLUSION REGARDING THE ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY?

A. The lower level of household income in the state and the higher level of unemployment in DEP's service territory (relative to the national average) suggest that affordability can be an issue for an essential utility service such as electricity. This observation does not take into the impact of the coronavirus on DEP's customers, as well as on the North Carolina and U.S. economies. Certainly, it does not justify an authorized ROE that is almost 100 basis points above the national average. And DEP's overall rate of return request has a significant impact on its overall requested increase in revenues.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call*.

Professor Woolridge's co-authored stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999), as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past 35 years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, and Washington, D.C. He has also testified before the Federal Energy Regulatory Commission.

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Academic Experience

Professor of Finance, the Smeal College of Business Administration, the Pennsylvania State University (July 1, 1990 to the present).

> **President, Nittany Lion Fund LLC,** (January 1, 2005 to the present)
> **Director, the Smeal College Trading Room** (January 1, 2001 to the present)
> **Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration** (July 1, 1987 to the present).

Associate Professor of Finance, College of Business Administration, the Pennsylvania State University (July 1, 1984 to June 30, 1990).
Assistant Professor of Finance, College of Business Administration, the Pennsylvania State University (September, 1979 to June 30, 1984).

Education

Doctor of Philosophy in Business Administration, the University of Iowa. Major field: Finance.
Master of Business Administration, the Pennsylvania State University.
Bachelor of Arts, the University of North Carolina. Major field: Economics.

Books

James A. Miles and J. Randall Woolridge, *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation), 1999
Patrick Cusatis, Gary Gray, and J. Randall Woolridge, *The StreetSmart Guide to Valuing a Stock* (2nd Edition, McGraw-Hill), 2003.
J. Randall Woolridge and Gary Gray, *The New Corporate Finance, Capital Markets, and Valuation: An Introductory Text* (Kendall Hunt, 2003).

Research

Dr. Woolridge has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance*, the *Journal of Financial Economics*, and the *Harvard Business Review*.

Appendix B
The Coronavirus and Utility Capital Costs

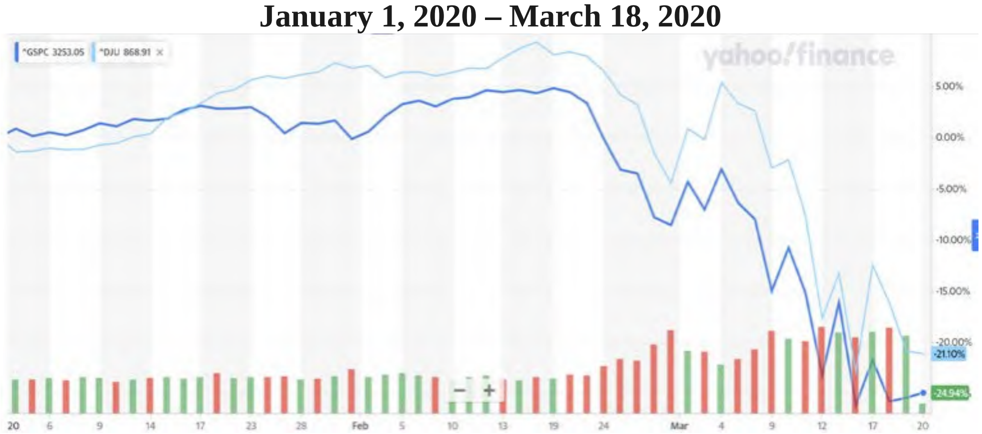
Q. PLEASE DISCUSS THE IMPACT OF THE CORONAVIRUS ON THE FINANCIAL MARKETS.

A. The financial markets around the world have been in chaos since the middle of February when the news of the spread of the coronavirus was recognized as a major risk factor for the world's population and global economy. An outbreak of coronavirus disease 2019 (COVID-19) caused by the 2019 novel coronavirus (SARS-CoV-2) began in Wuhan, Hubei Province, China in December 2019, and has spread throughout China and to over 170 countries and territories around the world, including the United States. As of mid-March, the coronavirus was officially identified by the World Health Organization as a global pandemic, and there were over 150,000 people reported infected and over 3,000 deaths worldwide. Investors around the world began to focus on the potential economic consequences of the coronavirus in the middle of January.[1] However, the markets largely shrugged off the impact of the virus until the third week of February. Since that time through mid-March, as shown in Figure 1, the S&P 500 has declined from almost 3,400, an all-time high, to about 2,300, over a 20% decline. The Dow Jones Utility Index ("DJU") is also shown in Figure 1, and it has also declined by over 20% since mid-February. Over the same period, investors fled to low risk financial

[1] Akane Otane, "Coronavirus Tests Market's Faith in Global Economy" *Wall Street Journal*, January 28, 2020.

assets, most notably long-term Treasury bonds. As shown in Figure 2, the yield on the benchmark 30-year Treasury bond declined from 2.0% to 1.6%, but has even traded as low as 0.9%, an all-time low, between February and March. Furthermore, the day-to-day volatility of prices in financial markets has been at extremes. The VIX, which is the Chicago Board Options Exchange (CBOE) volatility index, is shown in Figure 3 and has increased from 15 to over 50 over the same period, a level that has not been seen since the financial crisis in 2008.

Figure 1
S&P 500 and Dow Jones Utility Index
January 1, 2020 – March 18, 2020



Appendix B
The Coronavirus and Utility Capital Costs

Figure 2
30-Year Treasury Yield
January 1, 2020 – March 18, 2020

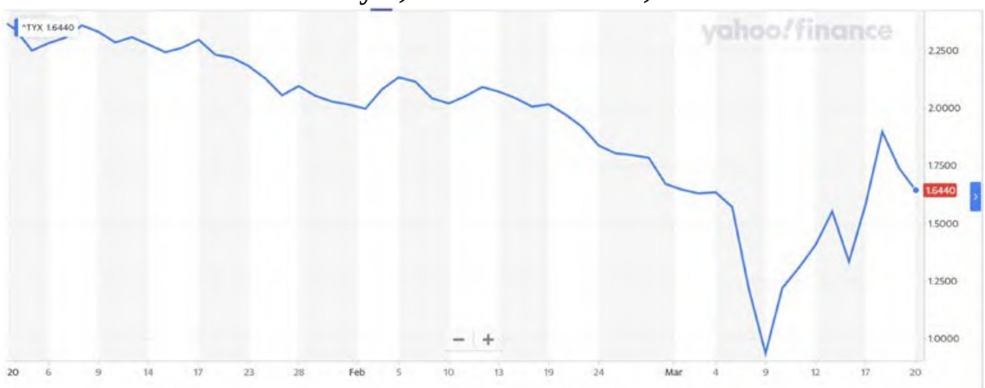
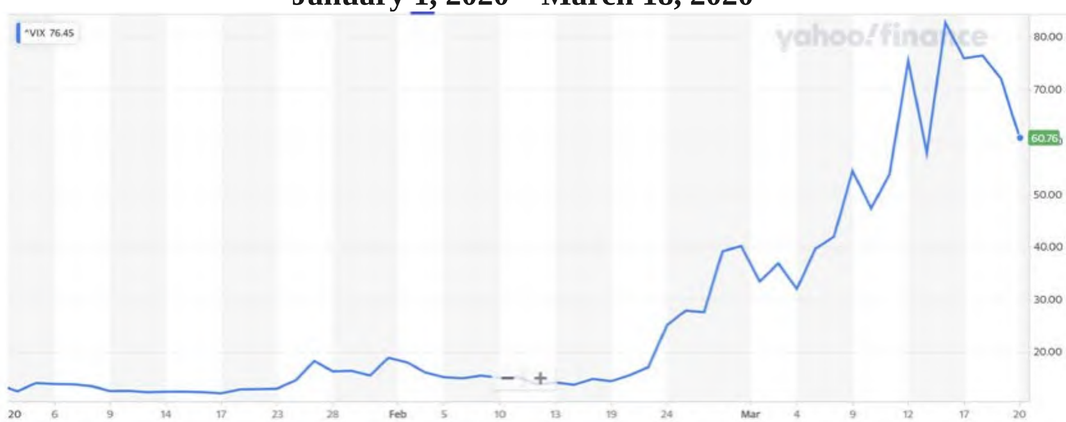


Figure 3
VIX – CBOE Volatility Index
January 1, 2020 – March 18, 2020



The spread of the coronavirus, and its impact on the world's population, the global economy, and financial markets, has become the primary focus of investors. The large day-to-day market gyrations, with historically large changes in the stock market and interest rates, are associated with huge flows of funds into and out of stocks and bonds, usually in response to updated new reports. The decline in stock prices and interest rates, and the daily volatility, is constantly discussed and debated on business news programs such as CNBC and Bloomberg as investors try to assess when things will settle down and the financial markets will return to conditions that are more normal.

Q. GIVEN THESE CONDITIONS, WHAT IS YOUR OPINION ABOUT THE STATE OF THE CURRENT FINANCIAL MARKETS AND CAPITAL COSTS?

A. I believe that the emotions of the market and the great uncertainty over the future impact of the coronavirus have resulted in markets that have become disconnected from fundamentals.

Q. WHAT DO YOU MEAN BY FUNDAMENTALS?

A. Investors tend to focus on various fundamental economic, industry, and company factors in assessing and developing risk and expected return expectations in alternative financial markets and securities. These factors include, but are not limited to, the following: (1) global and national economy factors such as gross domestic product (GDP) and industrial production growth, inflation, interest rates, etc.; (2) industry factors, such as the sensitivity to overall economy, the product/service life cycle and whether products/services are life necessities or discretionary, etc.; and (3) company specific factors, such as the company's strategy (in what product/service markets does it compete), the elasticity of demand for products/services, product service quality, the execution of management, financial performance, and ultimately expected revenue and earnings growth rates, etc.

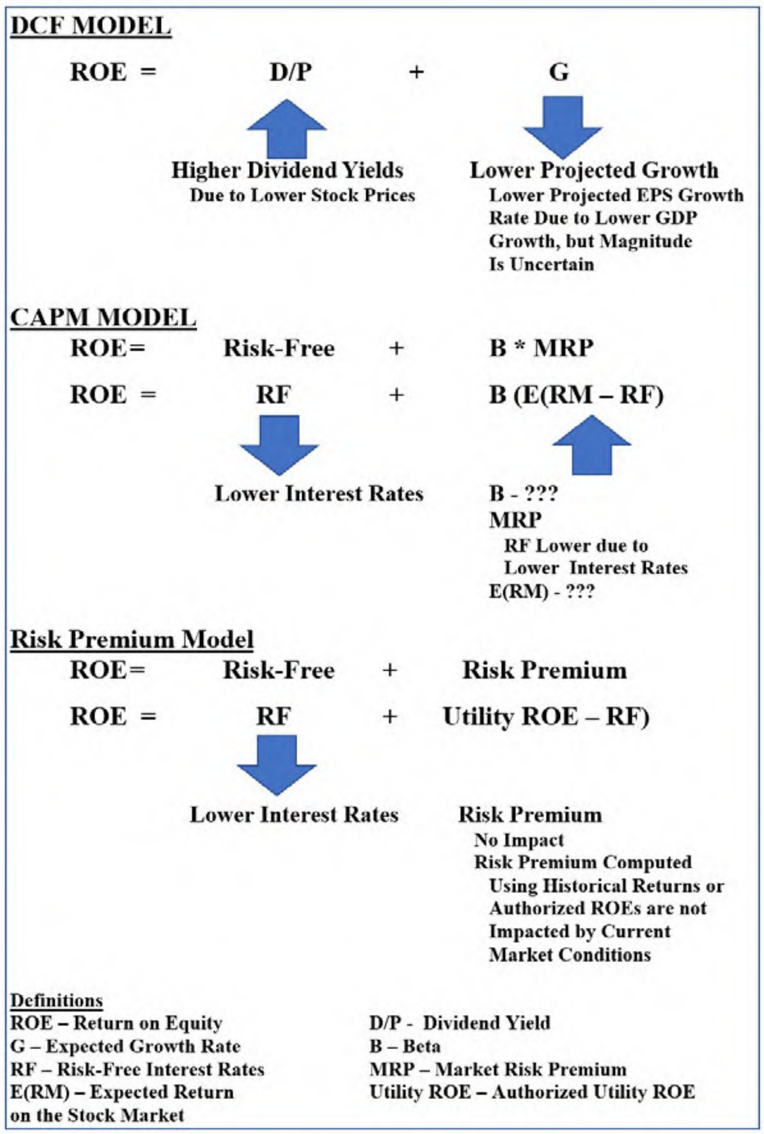
Q. WHY DO YOU BELIEVE THAT THE MARKETS ARE NOT TRADING ON THESE FUNDAMENTALS?

A. The great uncertainty and risk associated with coronavirus – the virus spread and associated mortality and the duration of the pandemic and associated factors, and the overall impact on the global economy, is totally unknown at this point. The potential range of outcomes is huge. As a result, baseline forecasts for the economy, different industries, and ultimately individual companies are either unknown or highly uncertain. I believe that, in the current environment, investors cannot rely on fundamental factors to value stocks and bonds based on traditional valuation procedures and measures. Instead, investors are reacting to daily news reports and updates on the virus as to whether the situation is getting better or worse and then allocating their investment funds accordingly.

Q. IN YOUR OPINION, HOW DOES THE CURRENT MARKET SITUATION IMPACT THE ESTIMATION OF THE COST OF EQUITY CAPITAL FOR A REGULATED PUBLIC UTILITY?

A. Figure 4 shows the three primary methods commonly used in rate cases to estimate the cost of equity capital, or ROE, for a regulated public utility. These are the Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), and risk premium approaches. In the figure, I show the components of each model, as well as the directional impact on each component associated with the economic changes and the lower interest rates and stock prices of the last month.

Figure 4
ROE Models and the Financial Markets Turmoil



With the DCF model, the lower stock prices have led to an increase in the dividend yield (D/P). This is directly observable. But the impact of the current environment on the expected DCF growth rate is tougher to assess. While this growth rate is a long-term growth rate, the significant slowdown in economic growth associated with the coronavirus will likely cause analysts to reduce their three- to five-year earnings per share (EPS) growth rate estimates for all companies. And while public utilities will not take a big hit like some industries, a slowdown in the economy and commercial and business activities will very likely have a short-term negative impact on the demand for energy by utility industrial, commercial, and consumer customers. However, since the ultimate impact of the virus is unknown at this time, any updates to analyst forecasts are highly speculative at this time.

The CAPM requires the estimation of three components: the risk-free interest rate, beta (B), and the market risk premium (MRP):

(1) Risk-Free Rate - The risk-free rate is usually measured by the yield on the 30-year Treasury bond, which is directly observable. As noted, these yields have been moving up and down on a day-to-day basis, primarily in response to the market's appetite for risk. Since these rates are directly observable, and have decreased by about 40 basis points in the last month (2.0% to 1.6%), this component of the CAPM is lower:

(2) Beta - Beta is normally estimated by regressing historical stock returns for an individual company on the returns of the overall

market (usually the S&P 500) over periods up to five years. Betas depend mostly on: (1) the company's industrial sector; and (2) the company's strategy (such as debt versus equity financing policies). Utility and consumer staples stocks are less risky and have betas less than 1.0. Biotech and energy stocks are more risky than the market and have betas greater than 1.0. But since betas are estimated using historic returns for periods up to five years, the recent disruption is not likely to have an impact on utility betas; and

(3) Market risk premium (MRP) - the most important and uncertain component of the CAPM is the MRP. The MRP is measured as the expected return on the stock market (E(RM)) minus the risk-free interest rate (RF). Given the lower interest rates (RF) of the last month, the MRP directly increases. However, the big unknown in calculation of the MRP is the expected return on the stock market E(R), which Nobel Prize winning economist Merton Miller once called the Greatest Mystery in Finance.[2] There are three general ways to measure the MRP: (1) Historical returns - the difference between historical stock and bond returns; (2) Expected return models – estimate the expected returns on stocks and bonds, normally using models with fundamental factors such as projected earnings and dividend growth rates; and (3) Surveys – there are a

[2] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, p. 3.

number surveys of financial professionals and academics regarding expected returns and the MRP. Given the market changes over the past month, only application of a current expected return model would likely to capture any effect. However, in this environment, as discussed below, estimates of the E(R) are very indeterminate, since these models normally rely, in part, on analysts' forecasts of three-to-five year EPS growth rates, and these forecasts would appear to be difficult to make given the highly uncertain economic environment.

Finally, while the CAPM is a form of the risk premium model, some analysts use a more general form of a risk premium approach. The indicated ROE from risk premium models is equal to: (1) the risk-free interest rate; plus (2) the risk premium. The risk-free rate component of the risk premium model is directly observable and has decreased by about 40 basis points (2.0% to 1.4%). Risk premium models usually measure the risk premium component of the model in one of two ways: (1) Historical utility stock and bond returns - the risk premium is the difference between historical utility stock and bond returns; or (2) Historical utility authorized ROEs – the risk premium is based on difference between authorized ROEs and the level of interest rates. The risk premium in the utility stock and bond returns approach, since it is based on historical returns, is not impacted by the current market environment. The risk premium in the historical utility authorized ROEs approach is usually computed using a regression of the historical authorized ROEs for public utility companies on the historical 30-year Treasury yield (the risk-free rate at the time of a ROE rate case decision). As with the utility stock and bond return approach, the authorized ROE approach is not impacted by the current environment because it is based on historical and not current market data. Therefore, the risk premium component of the risk premium model is not impacted by the current environment in either approach.

Q. GIVEN THE DISCUSSON ABOVE, AND THE CURRENT FINANCIAL MARKET SITUATION, WHAT DO YOU CONCLUDE ABOUT ESTIMATING THE COST OF EQUITY CAPITAL TODAY?

A. I believe that the current market situation makes it very difficult to make a reasonable estimate of the cost of equity capital, using current market data. As discussed above, I believe that the great volatility in the financial markets is a function of the emotions of the market and the great uncertainty over the future impact of the coronavirus. As a result, I believe that the markets have become disconnected from fundamentals. Therefore, the three traditional cost of equity capital models, which use fundamental market data, are unlikely to provide reasonable estimates of the cost of equity capital for several reasons:

(1) DCF Model – The dividend yield is readily observable since dividends and stock prices are directly observable. But, I

believe the expected long-term growth rate is a concern. As noted, the long-term growth rate is usually based, in part, on analysts' three-to-five year EPS growth rate estimates. And while it is likely that these growth rates will be lowered due to the significant slowdown in economic growth associated with the coronavirus, the magnitude of any likely reduction is highly indeterminate due the great uncertainty involving the spread of the virus and its impact on the economy;

(2) CAPM Approach – The CAPM has three components – the risk-free interest rate, beta, and MRP. The impact of the decrease in the risk-free interest rate yield is directly observable. Betas are measured using historical returns and so are not impacted by the current environment. The impact of the current environment on the MRP is very uncertain. The MRP is measured as the E(RM) – RF. The MRP increases by the lower level of the risk-free interest rate. However, the impact of the current environment on E(RM) is highly uncertain. As noted, historical return and survey approaches to estimating the MRP would not capture the changes over the past month. And the expected return models would suffer from the same issue as the DCF model. Namely, estimates of the E(R) are very indeterminate, since these models normally rely, in part, on analysts' forecasts of three-to-five year EPS growth rates, and these forecasts would appear to be very difficult to make given the highly uncertain economic environment; and

Appendix B
The Coronavirus and Utility Capital Costs

(3) Risk Premium Approach – As noted above, the risk premium approach is based on historical utility stock and bond returns or authorized utility ROEs minus the risk-free interest rate. As noted, the risk-free rate component is directly observable, and is lower in the current environment. Since both the historical returns and the authorized ROEs approaches to estimating the risk premium component do not change with the current environment, the risk premium is not impacted by the current environment. Therefore, the ROE calculated using the general historical risk premium model should be lower due to the current lower risk-free interest rate.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE USE OF COST OF EQUITY CAPITAL MODELS IN THE CURRENT FINANCIAL MARKET SITUATION TO ESTIMATE THE COST OF EQUITY CAPITAL FOR A PUBLIC UTILITY TODAY?

A. Yes. Financial models such as the DCF and CAPM models are models developed theoretically in a normative sense with a number of simplifying and in many cases unrealistic assumptions. The application of such models in the real world is known as positive economics. That is, despite the unrealistic nature of some of the assumptions, economists apply the models to assess whether the models provide reasonable results. However, these models rely on the precondition of “In equilibrium . . .” In other words, the normative and positive forms of the model presume that the markets are in equilibrium. In terms of financial markets, market equilibrium requires that a market price is established through competition such that the amount of a financial asset (stock or bond) sought by buyers is equal to the amount of a financial asset available to sellers. Classical macroeconomic theory assumes that if all buyers and sellers have access to information and there is no 'friction' impeding price changes, then prices always adjust up or down to ensure market clearing. The price that is established is called the market clearing price, and it follows a process by which the supply of a security that is traded is equated to the demand, so that there is no leftover supply or demand. In other words, the market-clearing price is one that causes quantities supplied and demanded to be equal.

Q. DO YOU BELIEVE THAT THE MARKETS ARE IN EQUILIBRIUM?

A. No. The volatility in the stock and bond markets since the middle of February in association with the expansion of the coronavirus provides direct evidence that the markets are is not in equilibrium. As discussed above, I believe that the emotions of the market and the great uncertainty over the future impact of the coronavirus have resulted in markets that have not been able to achieve stable, equilibrium market-clearing prices. As a result, I believe that security prices are disconnected from fundamentals, and therefore traditional financial models such as the DCF and CAPM models do not provide reliable estimates of the cost of equity capital.

Q. HOW HAVE YOU TAKEN THESE OBSERVATIONS IN ACCOUNT IN ESTIMATING OF COST OF EQUITY CAPITAL FOR DEP?

A. I used the traditional DCF and CAPM models to estimate an equity cost rate for DEP. However, I have used data as of the first week of February, which is before the market meltdown associated with coronavirus occurred. I believe that the volatility of the markets since mid-February suggests that the markets are not in equilibrium and therefore traditional models, using the current market data, do not provide reliable estimates of the cost of equity capital due to the great uncertainty over the future impact of the coronavirus.