INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Friday, September 16, 2022
TIME: 1:46 p.m. – 5:00 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 16

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

REPORTED BY: Joann Bunze		TRANSCRIPT PAGES:	156
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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, September 19, 2022

TIME: 1:46 p.m. - 5:00 p.m.

DOCKET NO.: E-100, Sub 179

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and
Duke Energy Carolinas, LLC,
2022 Biennial Integrated Resource Plans
and Carbon Plan

VOLUME: 16

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

A P P E A R A N C E S Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

A P P E A R A N C E S Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:

Andrea C. Bonvecchio,Esq.

The Law Offices of F. Bryan Brice, Jr.

127 West Hargett Street, Suite 600

Raleigh, North Carolina 27601

Carolina Leary, Esq.

1250 I Street Northwest, Suite 1000

Washington, DC 20005

FOR WALMART INC.:

Carrie H. Grundmann, Esq., Member

Spilman Thomas & Battle, PLLC

110 Oakwood Drive, Suite 500

Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:

Karen Weatherly, Esq., Senior Assistant City Attorney

600 East Fourth Street

Charlotte, North Carolina 28202

A P P E A R A N C E S Cont'd.:

FOR APPALACHIAN VOICES:
Catherine Cralle Jones, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

FOR REDTAILED HAWK COLLECTIVE, ROBESON COUNTY COOPERATIVE FOR SUSTAINABLE DEVELOPMENT, ENVIRONMENTAL JUSTICE COMMUNITY ACTION NETWORK, and DOWN EAST ASH ENVIRONMENTAL AND SOCIAL JUSTICE COALITION:
Ethan Blumenthal, Esq.
ECB Holdings LLC
1624 Nandina Comers Alley
Charlotte, North Carolina 28205

FOR NC WARN and
FOR CHARLOTTE-MECKLENBURG NAACP:
Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

A P P E A R A N C E S Cont'd.:

FOR BROAD RIVER ENERGY, LLC:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

FOR KINGFISHER ENERGY HOLDINGS, LLC, and
FOR PERSON COUNTY, NORTH CAROLINA:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

Kurt Olson, Esq.
The Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616

A P P E A R A N C E S Cont'd.:

FOR THE CITY OF ASHEVILLE and COUNTY OF BUNCOMBE:

Jannice Ashley, Esq., Senior Assistant City Attorney
City Attorney's Office
70 Court Plaza
Asheville, North Carolina 28801

Curt Euler, Esq., Senior Attorney II
Buncombe County
200 College Street, Suite 100
Asheville, North Carolina 28801

FOR MAREC ACTION:

Bruce Burcat, Esq, Executive Director
MAREC Action
Post Office Box 385
Camden, Delaware 19934

Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

A P P E A R A N C E S Cont'd.:

FOR TOTALENERGIES RENEWABLES USA, LLC, and
FOR CLEAN ENERGY BUYERS ASSOCIATION:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough LLP
4140 Parklake Avenue, Suite 200
Raleigh, North Carolina 27612

Weston Adams, Esq.
Nelson, Mullins, Riley & Scarborough LLP
1320 Main Street, Suite 1700
Columbia, South Carolina 29201

FOR PORK COUNCIL:
Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR COUNCIL OF CHURCHES:
James P. Longest, Jr., Esq.
Duke University School of Law
Box 90360
Durham, North Carolina 27708

A P P E A R A N C E S Cont'd.:

FOR AVANGRID RENEWABLES, LLC:

Benjamin Smith, Esq.

Todd S. Roessler, Esq.

Joseph S. Dowdy, Esq.

Kilpatrick Townsend & Stockton LLP

4208 Six Forks Road, Suite 1400

Raleigh, North Carolina 27609

FOR SEAN LEWIS:

Sean Lewis, Pro se

640 Firebrick Drive

Cary, North Carolina 27519

FOR THE USING AND CONSUMING PUBLIC, THE STATE, AND ITS CITIZENS:

Margaret Force, Esq., Special Deputy Attorney General

Tirrill Moore, Esq., Assistant Attorney General

North Carolina Department of Justice

Post Office Box 629

Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

Lucy Edmondson, Esq., Chief Counsel

Robert Josey, Esq.

Nadia L. Luhr, Esq.

Anne Keyworth, Esq.

William E.H. Creech, Esq.

William Freeman, Esq.

Public Staff - North Carolina Utilities Commission

4326 Mail Service Center

Raleigh, North Carolina 27699-4300

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E X H I B I T S

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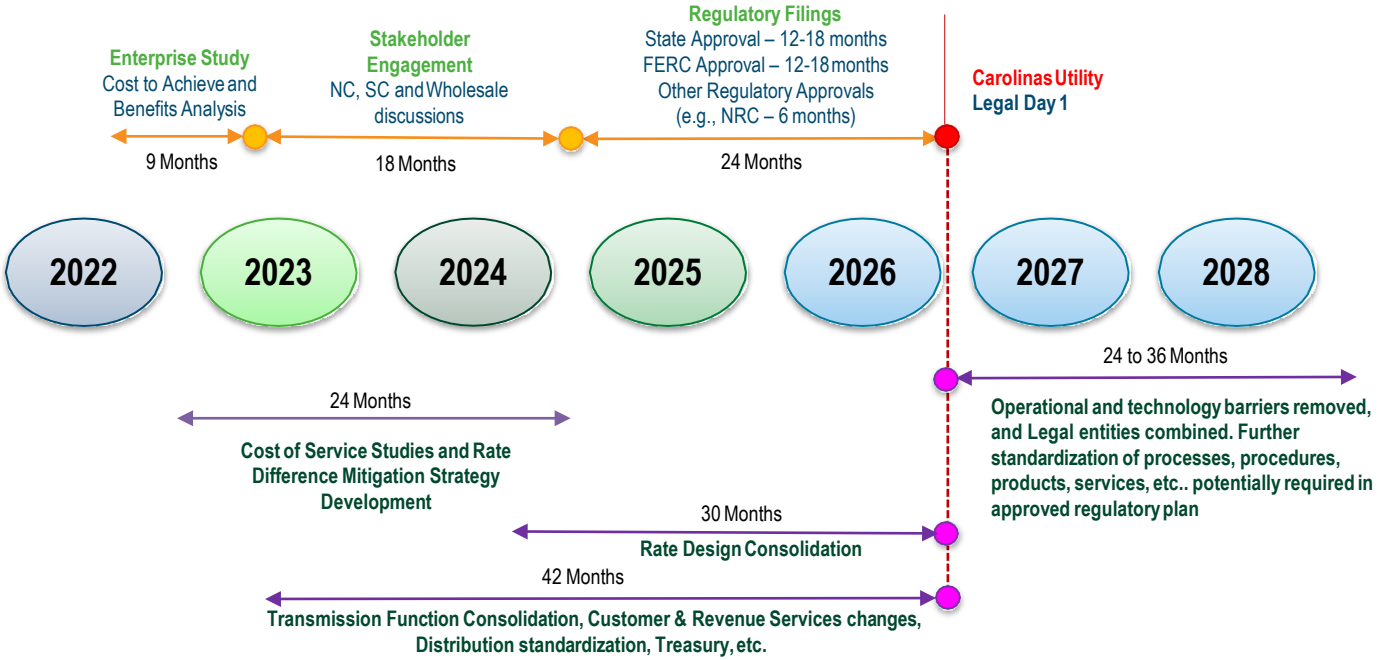

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please provide all studies done by or for Duke regarding the decline in industrial customers and/or sales associated with rate increases resulting from implementation of the Carbon Plan, as well as other cost increases outside the Carbon Plan. Please provide for the last filed Integrated Resource Plan and the Carbon Plan. Please include workpapers, models, and assumptions for both DEC and DEP.

RESPONSE:

The Companies are not aware of any studies or calculations regarding the impact of cost increases on the number of industrial customers in DEC or DEP. The Companies believe that the energy transition is beneficial to customers in that it will reduce exposure to diminishing coal supply and associated regulatory risks, provide for continued reliability, and ensure continued access to capital at reasonable rates. Regarding the impact of a cost increase on the volume of energy sold to industrial class customers, the load forecasting models described in Appendix F apply estimated elasticities of -0.013 for DEC and -0.098 for DEP.

Responder: Jeffrey Day, Principal Load Forecasting Analyst

THE ECONOMIC AND RATE IMPLICATIONS FROM AN ELECTRIC UTILITY'S LOSS OF LARGE-LOAD CUSTOMERS

REPORT PREPARED FOR:

DUKE ENERGY CAROLINAS & PROGRESS ENERGY CAROLINAS

REPORT PREPARED BY:

J. A. WRIGHT & ASSOCIATES

ST. THOMAS, VI

INITIAL DRAFT: SEPT 30, 2012

FINAL: MARCH 9, 2013

EXECUTIVE SUMMARY

The commercial and industrial electric consumer sectors are by and large the primary non-governmental economic engine of the US and the Carolinas, providing and supporting the predominance of employment and trade in the country and all the attenuating economic activity associated with these activities. Consequently, an important issue for policymakers to fully understand is the economic and rate implications should a large commercial or industrial customer either shut down or otherwise leave a region and a utility's service area.

Intuitively, if electricity is a major cost to a large electric load customer, the price of electricity can play a role in a firm's decision about a facility's location, expansion, or closing. Electric demand studies of industrial customers' price elasticity have indicated these type customers have a limited ability to respond to electric price changes in the short-run (less than 2-3 years). This means that in the short-run increased electricity costs, absent reductions in other costs, will likely have a very direct impact on these customers' profitability. From a longer-term perspective, price elasticity studies indicate that the industrial class of customers will respond very dramatically, as compared to some other customer classes, to changes in electricity prices up to and including the closing of a facility.

This report also confirmed the importance of reliable and favorably priced electricity to economic development and that the Carolinas are experiencing a transition in their economy, generally to more energy-intensive types of industries and facilities. However, another related finding in this research was that both states have been experiencing a decade long decline in the number of industrial customers with a related decline in employment in that sector of the economy. While some of these declines could be attributed to the recent recession, the industrial job losses and declining electric usage in the industrial class began well prior (at least as early as 2001) to the current recession (2007-08). This trend indicates that the loss of these type customers is due to more systemic based problems with impacts beyond the normal business cycle. For example, Duke Energy Carolina's ("Duke") 2011 IRP indicates that from 2001 up through 2010 it has lost approximately 1000 customers from its industrial class, while gaining customers in every other customer classification. During that same time period, while all other classes saw growth in energy sales, Duke's Industrial class saw a decline from 26,902 GWh to 20,618 GWH, a decline of 23.3%. Over a similar time period, according to the Progress Energy Carolina's ("PEC") 2011 IRP, PEC's Industrial Class of customers' sales over that time period declined by 15.9%.

To address these issues will likely require efforts aimed at reducing the underlying costs related to a particular industry – such as efforts aimed at

lowering labor costs, regulatory costs, or input costs including electricity. All these strategies could be productive attempts for helping reinvigorate industrial growth. Consequently, electric policy decisions specifically as it relates to rates are likely important issues for both states with respect to large customer retention and economic development.

To demonstrate the importance of large electric customers to a region or state, this report utilized an input-output econometric model to quantify the economic impact on the Charlotte, NC metropolitan region from the expansion or closing of four different large electric customer facilities. The specific facilities examined were an AT&T data center, a Caterpillar heavy equipment manufacturing facility, a surgical products manufacturing facility, and a plastic products manufacturing facility. Note that the analysis was performed using Duke data and economic information regarding the Charlotte, NC region. However, as the report states, the basic economic analysis and results would be expected to be generally similar for PEC.

The results of this analysis indicated that for every new (or lost) employee at the specified facility:

- There are from 1-3 additional new jobs created (lost) in the region,
- There is a region-wide increase (loss) of approximately $500K per year in additional economic output, and
- There is a region-wide increase (loss) of $200K-$350K in employee earnings.

Beyond these more region-wide economic impacts there could be an effect on the remaining customers' rates when large electric users depart any regulated electric utility's system. When electric load is lost from customers severely cutting back on load; moving out of an electric utility's service territory; or by going out of business entirely, the remaining customers will theoretically have to pay the fixed costs (non-energy related) portion of revenues no longer being recovered from the "lost" customer. A portion of the "lost' revenues are directly due to the change in electricity sales to the lost customer. However, there are additional changes in electricity usage in that customer's geographic region and these changes are related to the economic multiplier effects discussed above. Theoretically, the lost fixed costs attributed to the change in electricity usage related to this multiplier effect will also have to be recovered from the remaining customers.

Based on these assumptions about fixed cost recovery, publicly available data from the FERC, Duke's and PEC's North Carolina SCP cost of service study,[1] the BEA, and from the EIA was used to develop models to calculate

[1] Docket No. E-7, Sub 989 and Docket No. E-2, Sub 1023.

the dollar amounts of "lost" fixed costs and the resulting rate impacts, both related to the specific customer's electricity usage and the usage related to the economic multiplier effect. Again note that the analysis, while performed using Duke data and economic information regarding the Charlotte, NC region, would be expected to produce generally similar rate impacts for PEC..

Assuming varying percentages of load lost in Duke's "I" and "OPT" customer classes, these "lost" fixed costs were then re-allocated to the remaining classes of customers consistent with Duke's 2011 cost of service studies in order to estimate the rate impact on the remaining customer classes. The resulting analysis indicated that for a 1% loss of load in the I customer class, the Residential customers would theoretically experience an increase in their rates of $450,000 or 0.0212% due directly to the departing facility's lost load. The economic multiplier effect increased this rate impact to 0.0647%. A 5% Industrial class load loss resulted in a Residential rate increase of $2.249 million or 0.106% due directly to the departing facility's lost load. The economic multiplier effect increased this rate impact to 0.323%. A similar analysis estimated that the Residential Class of customers would experience a rate increase of approximately $3.9 million or 0.184% for the loss of 1% of the load in the OPT class due directly to the departing facility's lost load. The economic multiplier effect increased this rate impact to 0.561%. The allocation of fixed costs resulting from as much as a 5% loss in load from the OPT customer class would result in a 0.919% increase in the remaining customers' rates due directly to the departing facility's lost load. The economic multiplier effect increased this rate impact to 2.804%.

For PEC, the loss of large load customers in PEC's LGS class has generally similar rate impacts. For example, a 5% loss of PEC's LGS load would theoretically mean that Residential customers would experience a 0.40% increase in their electric rates due to the recovery related to the departing customer's lost fixed costs. In addition, the economic multiplier effect increases this Residential rate impact to an increase of 1.23%. PEC's small general service customers would be similarly affected.

The overall results from this economic and rate analysis yield three basic conclusions. First, that the economic multiplier effect on a region's electricity consumption (and revenues) are expected to be larger than are the changes in electricity consumption resulting directly from a large customer's usage when that customer exits or expands into a utilitiy's system. Second, that the loss (or gain) of a larger customer (assume 3% to 5% of Duke's OPT load or PEC's LGS load) would theoretically result in Residential (and also General Service) customers experiencing rate increases (or decrease) ranging from approximately 1% to 3%.

The third and likely most important conclusion from this economic analysis is that a comparison of the rate and economic impacts that accrue from the attraction of new, expanded, or retained large load customers are likely far larger in economic value than the negative rate impacts should these customers leave Duke's or PEC's system. Consequently, to the extent that electric rate setting decisions have the potential for retaining or attracting large customers to a region, it would seem appropriate for policy makers to consider both the rate impacts and the economic impacts resulting from such decisions. In so doing, when establishing electric pricing terms and conditions electric rate-setting policy makers may find it reasonable and in the public interest to depart from historical or strictly applied rate-setting methodologies and rules if larger customers' retention hangs in the balance.

Further research in this report supported this conclusion by finding that a number of states and electric utilities have developed tariffs with discounted pricing options with the objective of both large customer retention and economic development and in some cases states have used these terms and resulting tariffs interchangeably. There are usually several criteria that these types of retention, special contract, or economic development tariffs adhere to including:

- Rate concessions vary, sometimes stated in the tariff, other times the tariff indicates rates will be negotiated
- Some tariffs state the minimum rate will be the utility's marginal cost plus some contribution
- A customer's minimum peak demand varies from as low as 150 kW to as high as 1500 kW
- Some utilities require that the company receiving the new rate participate in an energy audit or in other energy conservation measures
- In some cases, the customer receiving the new rate must provide an affidavit affirming the need for the rate to remain viable. In other cases the company receiving the new rate must provide documentation the utility considers sufficient to affirm that the rate is justified for that particular customer, and in some states no affidavit or documentation from the customer is required
- Sometimes there is a contract limit, and if so, it is usually no more than 5 year contract limit

Given these various considerations, it would not be unwarranted should Duke or PEC seek to obtain a tariff focusing on retaining jobs with the additional benefit of aiding in keeping customers on the Company's system and in the State. The analysis in this report indicates that such a tariff, to the extent large electric loads were retained on the system, provides substantial positive economic benefits to a region with potentially minor increases in the remaining customers' rates.

CHAPTER 1: INTRODUCTION

1.0 INTRODUCTION AND PURPOSE

According to the Energy Information Administration ("EIA"), in the United Sates ("US"), from 1950 to 2000, industrial and commercial customers used approximately two-thirds of the electricity consumed in the country (see **Chart 1.1** below). Since 2000, that figure has declined slightly, but nevertheless, the commercial and industrial electricity consumer sectors continue to use the majority of the electric power consumed in the US.[2] In North Carolina and South Carolina, ("Carolinas" collectively) the percentage of statewide total electric sales by kWh to the commercial and industrial sectors, according to the EIA, was 46% and 51%, respectively, of total kWh electric sales in 2011.[3] For Duke Energy Carolinas ("Duke") specifically, the percentage of energy sales to its commercial and industrial customers represents 58% of the Company's total energy sales.[4] For Progress Energy Carolinas ("PEC") the percentage of energy sales to its commercial and industrial customers represents 56% of the Company's total energy sales.[5] Moreover, the commercial and industrial electric consumer sectors are a significant economic engine for the entire US and the Carolinas' economy, providing and supporting a large portion of non-government employment and trade in the country and all the attenuating economic activity associated with these activities.

Given the importance of these industrial electric consumers to a region and to the US economy, it is important for policy makers to fully understand the economic and rate implications should a large industrial customer either shut down or otherwise leave a region and a utility's service area. To study this question Duke Energy and Progress Energy Carolinas engaged J. A. Wright & Associates ("JAW") and this report is the result of that research. This issue is particularly important not only from the perspective of retention but also at the state and smaller-region level where there is intensive competition for and recruiting of large-employee enterprises, such as a big manufacturing facility. A necessary component of that recruiting effort is often a region's availability of reliable and affordable electric power.

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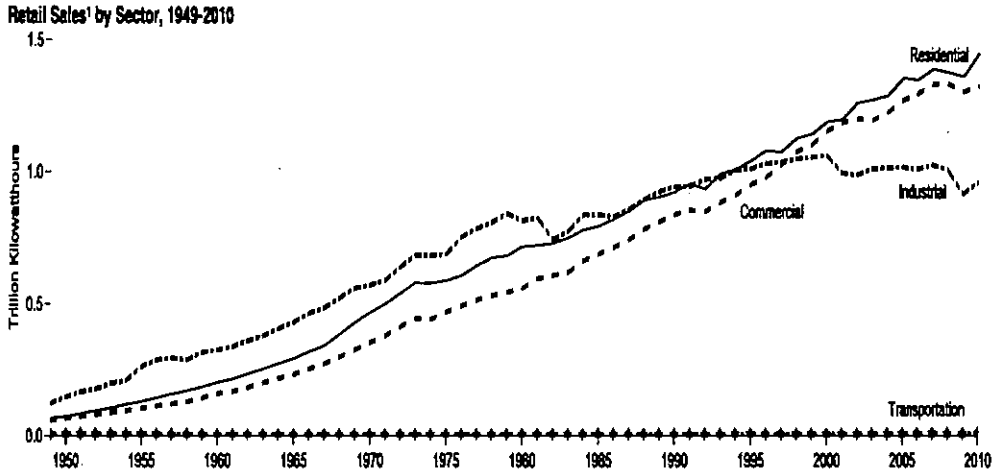
[2] See EIA, 2011 data tables for electricity at: http://www.eia.gov/electricity/data.cfm#sales.

[3] IBID.

[4] Duke Carolinas IRP, Annual Report, Sept. 2011, p. 18.

[5] Progress Energy Carolinas IRP, Sept. 1, 2011.

CHART 1.1



[1] Electricity retail sales to ultimate customers reported by electric utilities and, beginning in 1996, other energy service providers.

[2] Use of electricity that is 1) self-generated, 2) produced by either the same entity that consumes the power or an affiliate, and 3) used in direct support of a service or industrial process located within the same facility or group of facilities that house the generating equipment. Direct use is exclusive of station use.

Source: Table 8.9.

At the outset, this study segregated the impacts resulting from a large electric customer leaving a region and a utility's, in this case Duke's or PEC's, service territory into two distinct categories.

The first category of impacts, discussed in **Chapter 3**, considered the basic economic effects on a region should a large electric customer depart that region. To study this question this research employed a literature review and a quantitative analysis that utilized econometric-modeling techniques supported by the US Department of Commerce Bureau of Economic Analysis.[6] The second category of impacts, discussed in **Chapter 4**, examined the rate-related impacts on the remaining customers should a large customer depart Duke's or PEC's service territory. This research used these two utilities publicly available accounting and customer data and employed basic regulatory ratemaking accounting in estimating these impacts. Finally, **Chapter 5** reviews a number of tariffs that are currently being used in the electric industry to promote large customer attraction and retention. Before

[6] Called RIMS II input-output modeling, further described and employed in **Chapter 3**.

proceeding with the findings from this analysis of the economic and rate impacts resulting from a large electric customer departing a region and electric system, the following Chapter reviews some relevant economic theory and data related to this analysis.

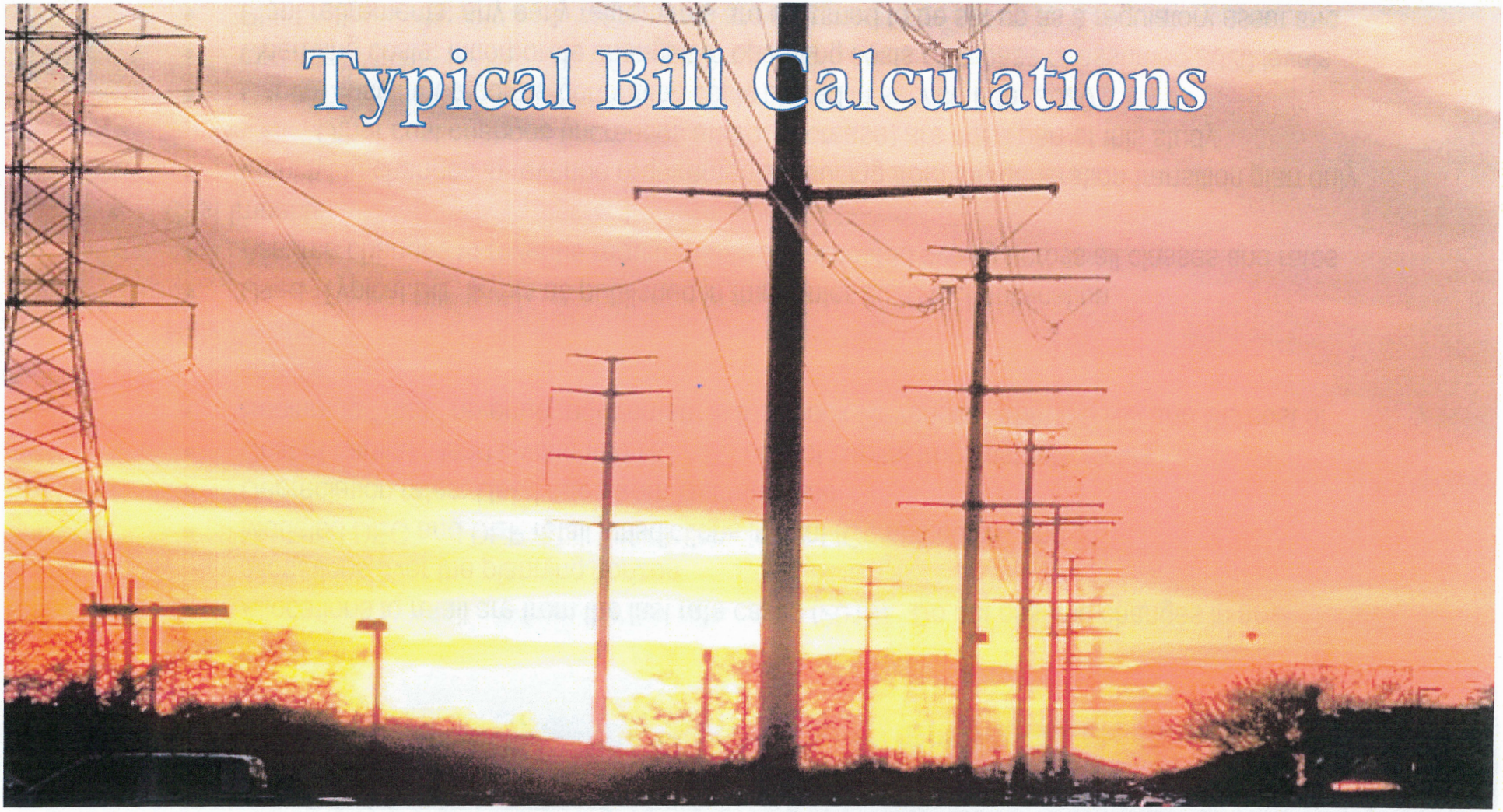
I/A

CIGFUR II & III
Initial Comments
Attachment A
Docket No. E-100, Sub 179

DUKE ENERGY

March 2020

Typical Bill Calculations



Bill Impact Modeling Assumptions

- Cost of service:
  - Allocations to retail are from the last rate cases (2019). Do not assume changes in any allocations over the planning horizon
  - Modeled DEC and DEP retail jurisdictions in total (Combined NC and SC)
  - Depreciation rates: Used rates from last rate case
  - Cost of capital: Used a weighted NC / SC cost of capital from last rate cases
  - Beginning "Total" revenue requirement is the "Book Revenues" from the NC and SC cost of service
- Rate Design
  - Used "Typical Bill" levels as published in the Winter 2020 EEI publication
  - Assume changes to revenue requirements are allocated evenly across all classes and rates
- Cost Impacts
  - Identifying changes in revenue requirements resulting from the generation transition plan only
    - Other cost changes (increases and/or decrease) are not a part of this study
  - Capital costs: Incorporate generation costs placed in service after 2020
  - Operating costs: Incorporate changes in operating costs off a base of assumed 2020 levels
  - Plant retirements: any early retirements are assumed to be set up as a regulatory asset and amortized at same rate as was being depreciated (i.e. no revenue requirement impact)
- Retail sales
  - Total retail sales are aligned with the 2020 IRP's

I/A

Estimated Bill Impacts

	DEC		DEP	
	January 1 2020 Typical Bill	2030 Change Base IRP	January 1 2020 Typical Bill	2030 Change Base IRP
RESIDENTIAL				
Household using 1,000 KWh	$ 111	$ 7	$ 116	$ 13
COMMERCIAL				
375 KWh	$ 66	$ 4	$ 70	$ 8
1500 KWH	$ 202	$ 12	$ 185	$ 21
10,000 KWh / 40 KW	$ 896	$ 55	$ 934	$ 105
14,000 KWh / 40 KW	$ 1,019	$ 62	$ 1,153	$ 130
150,000 KWh / 500 KW	$ 11,895	$ 726	$ 13,432	$ 1,512
180,000 KWh / 500 KW	$ 12,561	$ 767	$ 15,241	$ 1,716
INDUSTRIAL				
15,000 KWh / 75 KW	$ 1,416	$ 86	$ 1,666	$ 188
30,000 KWh / 75 KW	$ 2,075	$ 127	$ 2,564	$ 289
50,000 KWh / 75 KW	$ 2,947	$ 180	$ 3,720	$ 419
200,000 KWh / 1,000 KW	$ 17,657	$ 1,078	$ 25,634	$ 2,886
400,000 KWh / 1,000 KW	$ 27,495	$ 1,678	$ 37,958	$ 4,273
650,000 KWh / 1,000 KW	$ 37,683	$ 2,300	$ 50,675	$ 5,705
15,000,000 KWh / 50,000 KW	$ 1,000,725	$ 61,070	$ 1,491,705	$ 167,928
25,000,000 KWh / 50,000 KW	$ 1,414,303	$ 86,310	$ 2,107,917	$ 237,298
32,500,000 KWh / 50,000 KW	$ 1,743,561	$ 106,403	$ 2,435,641	$ 274,192
Average Annual Percentage Change		0.7%		1.2%

Incorporating Transmission and Distribution costs

The 14.7 billion is a 5 year total for total T&D costs for both DEC and DEP. The DEC equivalent is 9 billion.

Of the 9 billion – approximately 3 billion is Grid Improvement plan for DEC

To calculate the rate impact including the T&D costs:

- G.I.P. – used the 5 years totaling ~3 billion in the first five years. No costs were assumed after the 5 years
- Other Distribution – used the expected capital investments in the first first five years. For the remaining study period, used the average annual investment from the first five years
- Transmission – used the expected capital investments in the first five years. For the remaining study period, used the average annual investment from the first five years

Cost Allocations:

- distribution costs (G.I.P. and other expansion/reliability/maint/etc) were allocated to Residential, Commercial, and other
- Transmission costs were allocated to all customer classes

Built the revenue requirement up from the IRP base case

Have not yet considered the depreciation of existing rate base

I/A

Bill Impacts

Class	IRP Base Plan Avg Annual Impact 2030	IRP Base Plan Avg Annual Impact 2035	All T&D (Incl Grid Mod) Avg Annual Impact 2030	All T&D (Incl Grid Mod) Avg Annual Impact 2035	Total Impacts Avg Annual Impact 2030	Total Impacts Avg Annual Impact 2035	Average Monthly Bill 2020	Average Monthly Bill 2030	Average Monthly Bill 2035	Average Monthly increase in average bill 2020 to 2030	Average Monthly increase in average bill 2030 to 2035
RESIDENTIAL	0.7%	1.3%	2.3%	1.7%	3.0%	3.0%	$ 111	$ 145	$ 168	$ 4	$ 6
COMMERCIAL	0.7%	1.3%	2.3%	1.7%	3.0%	3.0%	$ 12,561	$ 16,362	$ 19,019	$ 422	$ 664
INDUSTRIAL	0.7%	1.3%	0.3%	0.2%	0.9%	1.6%	$ 1,743,561	$ 1,895,144	$ 2,170,071	$ 16,843	$ 68,732

FROM THE 2020 WINTER EEI TYPICAL BILL PUBLICATION

Residential - 1,000 KWh per month
Commercial - 180,000 KWh / 500 KW
Industrial - 32,500,000 KWh / 50,000 KW

Industrial Bill Impacts

Cumulative Inflation Rates	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IRP Base Case	0%	2%	3%	3%	3%	3%	3%	4%	5%	6%
All costs	0%	2%	4%	4%	4%	4%	5%	6%	7%	9%

IRP Base Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industrial - 15,000 KWh / 75 KW	$ 1,416	$ 1,443	$ 1,457	$ 1,461	$ 1,458	$ 1,454	$ 1,465	$ 1,476	$ 1,485	$ 1,502
Industrial - 30,000 KWh / 75 KW	$ 2,075	$ 2,114	$ 2,135	$ 2,141	$ 2,136	$ 2,131	$ 2,147	$ 2,163	$ 2,176	$ 2,202
Industrial - 50,000 KWh / 75 KW	$ 2,947	$ 3,003	$ 3,032	$ 3,040	$ 3,034	$ 3,026	$ 3,050	$ 3,072	$ 3,090	$ 3,127
Industrial - 200,000 KWh / 1,000 KW	$ 17,656	$ 17,992	$ 18,169	$ 18,215	$ 18,178	$ 18,133	$ 18,271	$ 18,408	$ 18,513	$ 18,735
Industrial - 400,000 KWh / 1,000 KW	$ 27,493	$ 28,016	$ 28,292	$ 28,364	$ 28,306	$ 28,236	$ 28,452	$ 28,665	$ 28,828	$ 29,173
Industrial - 650,000 KWh / 1,000 KW	$ 37,680	$ 38,397	$ 38,775	$ 38,874	$ 38,795	$ 38,699	$ 38,994	$ 39,286	$ 39,510	$ 39,983
Industrial - 15,000,000 KWh / 50,000 KW	$ 1,000,652	$ 1,019,685	$ 1,029,729	$ 1,032,354	$ 1,030,256	$ 1,027,693	$ 1,035,545	$ 1,043,293	$ 1,049,242	$ 1,061,795
Industrial - 25,000,000 KWh / 50,000 KW	$ 1,414,200	$ 1,441,099	$ 1,455,293	$ 1,459,003	$ 1,456,038	$ 1,452,416	$ 1,463,513	$ 1,474,464	$ 1,482,871	$ 1,500,613
Industrial - 32,500,000 KWh / 50,000 KW	$ 1,743,434	$ 1,776,595	$ 1,794,094	$ 1,798,668	$ 1,795,012	$ 1,790,547	$ 1,804,228	$ 1,817,728	$ 1,828,092	$ 1,849,964

All costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Industrial - 15,000 KWh / 75 KW	$ 1,416	$ 1,447	$ 1,467	$ 1,477	$ 1,478	$ 1,476	$ 1,491	$ 1,505	$ 1,518	$ 1,539
Industrial - 30,000 KWh / 75 KW	$ 2,075	$ 2,120	$ 2,150	$ 2,165	$ 2,165	$ 2,163	$ 2,184	$ 2,206	$ 2,224	$ 2,255
Industrial - 50,000 KWh / 75 KW	$ 2,947	$ 3,011	$ 3,053	$ 3,075	$ 3,075	$ 3,071	$ 3,102	$ 3,133	$ 3,159	$ 3,203
Industrial - 200,000 KWh / 1,000 KW	$ 17,657	$ 18,043	$ 18,292	$ 18,422	$ 18,425	$ 18,402	$ 18,588	$ 18,773	$ 18,925	$ 19,192
Industrial - 400,000 KWh / 1,000 KW	$ 27,495	$ 28,096	$ 28,484	$ 28,686	$ 28,691	$ 28,655	$ 28,944	$ 29,233	$ 29,470	$ 29,885
Industrial - 650,000 KWh / 1,000 KW	$ 37,683	$ 38,506	$ 39,038	$ 39,315	$ 39,322	$ 39,273	$ 39,669	$ 40,065	$ 40,390	$ 40,959
Industrial - 15,000,000 KWh / 50,000 KW	$ 1,000,725	$ 1,022,590	$ 1,036,709	$ 1,044,075	$ 1,044,248	$ 1,042,946	$ 1,053,474	$ 1,063,973	$ 1,072,608	$ 1,087,727
Industrial - 25,000,000 KWh / 50,000 KW	$ 1,414,303	$ 1,445,204	$ 1,465,159	$ 1,475,568	$ 1,475,813	$ 1,473,973	$ 1,488,851	$ 1,503,690	$ 1,515,893	$ 1,537,261
Industrial - 32,500,000 KWh / 50,000 KW	$ 1,743,561	$ 1,781,656	$ 1,806,257	$ 1,819,089	$ 1,819,390	$ 1,817,122	$ 1,835,465	$ 1,853,758	$ 1,868,802	$ 1,895,144

EXHIBIT A

Public Staff - H591 v10 Analysis $250 M Securitization - July 9, 2021[1, 10]	DEP + DEC				DEP						DEC					
	Base with Carbon Policy		H951 Legislative Impact Analysis		Base with Carbon Policy		H951 Legislative Impact Analysis				Base with Carbon Policy		H951 Legislative Impact Analysis			
PORTFOLIO	B[8]		PS 1		B		PS 1				B		PS 1			
Year	2030	2035	2030	2035	2030	2035	2030		2035		2030	2035	2030		2035	
							Total Cost with H951	Impact of H951[9]	Total Cost with H951	Impact of H951			Total Cost with H951	Impact of H951	Total Cost with H951	Impact of H951
System CO2 Reduction From 2005 Baseline[2]	59%	62%	62%	64%												
Average Annual Percentage Change in Retail Rates (through 2030 | through 2035)					1.1%	1.3%	1.3%	**0.1%**	1.3%	**0.0%**	0.9%	1.5%	1.4%	**0.4%**	1.6%	**0.1%**
Cumulative Percentage Change in Retail Rates (by 2030 | by 2035)					11%	19%	12%	**1.2%**	20%	**0.8%**	9%	23%	13%	**4.4%**	25%	**2.5%**
Year	2050		2050		2050		2050				2050		2050			
			Total Cost with H951	Impact of H951[9]			Total Cost with H951			Impact of H951			Total Cost with H951			Impact of H951
Present Value Revenue Requirement by 2050 (PVRR) [$B][3]	$82.5		$88.3	**$5.8**	$35.7		$37.1			**$1.4**	$46.8		$51.2			**$4.4**
Estimated Transmission Investment [$B][4]	$1.2		$1.8	**$0.5**	$0.5		$0.4			**-$0.1**	$0.8		$1.4			**$0.6**
Year	2035		2035		2035		2035				2035		2035			
			Total Cost with H951	Impact of H951			Total Cost with H951			Impact of H951			Total Cost with H951			Impact of H951
Total Solar [MW] by 2035[5]	12,187		15,656	**3,469**	3,372		3,687			**315**	4,890		8,044			**3,154**
New Onshore Wind [MW] by 2035	750		1,050	**300**	600		600			**0**	150		450			**300**
New Offshore Wind [MW] by 2035	0		0	**0**	0		0			**0**	0		0			**0**
New Total Storage [MW] by 2035[6]	2,140		2,391	**251**	1,562		1,332			**-230**	578		1,059			**480**
New Standalone Storage [MW] by 2035	1,313		1,605	**292**	1,152		940			**-212**	161		665			**504**
New PV-Coupled Storage [MW] by 2035	827		786	**-41**	410		393			**-18**	417		394			**-23**
New Gas [MW] by 2035	7,328		6,868	**-460**	4,276		4,274			**-2**	3,052		2,594			**-458**
Total EE and DSM Contribution [MW] by 2035	2,050		2,050	**0**	825		825			**0**	1,225		1,225			**0**
Coal Retirements[7]	Most Economic		Per Legislation		Most Economic		Per Legislation				Most Economic		Per Legislation			

Notes

1] The Public Staff bill impact analysis excludes the following portions of the bill as infeasible to quantify due to unknown factors, likely negligible impacts, or no change from the IRP:
- PBR and MYRR, with the exception of the assumption that the maximum PIM would be claimed in each year; Section 8 small power producers contract revisions; Solar Choice Tariff; solar leasing cap change (62-126.5(d)); fuel rider change (62-133.2(d)); nuclear Early Site Permit costs above $50 million (Section 3.(a)); nuclear Subsequent License Renewals (Section 3.(b)); Green Source Advantage for UNC and military customers change to bill credit options.
-The analysis presented here does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions, such as Duke's Grid Improvement Plan.

2] Combined DEC/DEP System CO2 Reductions from 2005 baseline

3] Represents specific IRP portfolio's incremental costs included in IRP analysis through 2050, and exclude the cost of CO2 as a tax.

4] Represents PVRR of network upgrades required to integrate new resources and coal transmission retirement costs. Included in PVRR figures.

5] Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected). Total solar under the legislation may be less than projected due to how Transition MW is defined and Duke's projected renewable capacity online by January 1, 2027.

6] Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro.

7] Most Economic is the retirement plan in the IRP. Per Legislation refers to PS interpretation of required retirement dates: Cliffside 5 is delayed by 5 years; Marshall is accelerated by 8 years. Other retirement dates are unchanged.

8] Portfolio B is from Duke's 2020 IRP, which the Public Staff has recommended the Commission to accept as reasonable for planning purposes (along with Portfolio A, base without carbon policy). Numbers for Portfolio B may not match Duke's filed IRP exactly due to slight differences in in-service years and baseline data.

9] The 'Impact of H951' column shows the incremental cost of H951, which is the difference between the total cost with H951 and the total cost of the Base Case with Carbon Policy (Portfolio B) from Duke's 2020 IRP in the specified year.

10] This analysis includes $250 million in securitization for each utility, rather than the $100 million in version 10. DEC securitizes Allen 1 and 5, Marshall 1, and portions of Marshall 2. DEP securitizes Roxboro.

I/A

EXHIBIT A

Public Staff - H591 v10 - $250 M Securitization Detailed Bill Impact Analysis Breakouts[1, 7]	DEP + DEC			DEP						DEC					
	Base with Carbon Policy	H951 Legislative Impact Analysis		Base with Carbon Policy		H951 Legislative Impact Analysis				Base with Carbon Policy		H951 Legislative Impact Analysis			
PORTFOLIO	B [5]	PS 1		B		PS 1				B		PS 1			
Year				2030	2035	2030		2035		2030	2035	2030		2035	
						Total Cost with H951	Impact of H951[6]	Total Cost with H951	Impactof H951			Total Cost with H951	Impact of H951	Total Cost with H951	Impact of H951
Average Annual Percentage Change in Retail Rates (through 2030 | through 2035)				1.1%	1.3%	1.3%	**0.1%**	1.3%	**0.0%**	0.9%	1.5%	1.4%	**0.4%**	1.6%	**0.1%**
Cumulative Percentage Change in Retail Rates (by 2030 | by 2035)				11%	19%	12%	**1.2%**	20%	**0.8%**	9%	23%	13%	**4.4%**	25%	**2.5%**
Average Monthly Residential Bill Impact (1,000 kWh/mo) (by 2030 | by 2035)[2]				$9	$17	$11	**$1**	$18	**$1**	$7	$21	$12	**$5**	$24	**$3**
Average Annual Percentage Change in Residential Bills (thru 2030 | thru 2035)				0.8%	1.0%	1.0%	**0.1%**	1.0%	**0.1%**	0.7%	1.2%	1.1%	**0.5%**	1.4%	**0.2%**
Cumulative Percentage Change in Residential Bills (by 2030 | by 2035)				8%	15%	9%	**1.3%**	15%	**0.9%**	6%	19%	11%	**4.5%**	21%	**2.5%**
Average Annual Percentage Change in Commercial Bills (thru 2030 | thru 2035)[3]				1.3%	1.5%	1.5%	**0.2%**	1.6%	**0.1%**	0.9%	1.4%	1.3%	**0.4%**	1.5%	**0.1%**
Cumulative Percentage Change in Commercial Bills (by 2030 | by 2035)				13%	23%	14%	**1.5%**	24%	**1.1%**	8%	21%	12%	**3.9%**	23%	**2.0%**
Average Annual Percentage Change in Industrial Bills (thru 2030 | thru 2035)[4]				1.1%	1.2%	1.1%	**0.1%**	1.2%	**0.0%**	0.9%	1.7%	1.6%	**0.7%**	2.0%	**0.3%**
Cumulative Percentage Change in Industrial Bills (by 2030 | by 2035)				10%	19%	11%	**0.6%**	19%	**-0.1%**	8%	27%	15%	**6.7%**	31%	**4.5%**
Year	2050	2050		2050		2050				2050		2050			
		Total Cost with H951	Impact of H951			Total Cost with H951			Impact of H951			Total Cost with H951			Impact of H951
Present Value Revenue Requirement (PVRR) [$B]	$82.5	$88.3	**$5.8**	$35.7		$37.1			**$1.4**	$46.8		$51.2			**$4.4**

Notes

1] These allocations to customer classes are based on estimates, and are not as precise as could be determined via a full allocation analysis. Changes in class allocation factors over time are assumed proportional to energy sales.

2] Residential bill impacts are estimated using residential allocation factors.

3] Commercial bill impacts are estimated using commercial allocation factors for small and medium customers.

4] Industrial bill impacts are estimated using industrial allocation factors for small, medium, and large customers.

5] Portfolio B is from Duke's 2020 IRP, which the Public Staff has recommended the Commission to accept as reasonable for planning purposes (along with Portfolio A, base without carbon policy).

6] The 'Impact of H951' column shows the incremental cost of H951, which is the difference between the total cost with H951 and the total cost of the Base Case with Carbon Policy (Portfolio B) from Duke's 2020 IRP in the specified year.

7] This analysis includes $250 million in securitization for each utility, rather than the $100 million in version 10. DEC securitizes Allen 1 and 5, Marshall 1, and portions of Marshall 2. DEP securitizes Roxboro.

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please state whether the Utilities modeled cost estimates and bill impacts in the event that the Public Service Commission of South Carolina does not approve the Carbon Plan in the 2023 Integrated Resource Plan proceeding and/or otherwise disallows cost recovery from the Utilities' South Carolina ratepayers for any investments considered to be made pursuant to House Bill 951. If not, please state why not.

RESPONSE:

The Companies have not formally assessed the costs or bill impacts of the Carbon Plan in a scenario in which the PSCSC does not approve the Carbon Plan or otherwise disallows Carbon Plan-related investments. As explained in the Carbon Plan, the Companies intend to seek continued alignment between the states. To the extent that alignment cannot be achieved, it will be necessary for each state to separately plan to serve its respective retail load. Nevertheless, the Companies believe that the near-term activities proposed in its Carbon Plan are prudent and reasonable under a future extreme scenario in which the dual-state approach to planning is discontinued. As explained in the Carbon Plan, the Companies expect to have more clarity in the 2024 Carbon Plan proceeding regarding the extent of state alignment, at which point the Commission can determine how to modify and adjust the Carbon Plan.

Responder: Lara Nichols, Vice President, State and Federal Regulatory Legal Support

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please reference the Carbon Plan, Executive Summary, page 4, where in the Companies discuss the potential for "ultimate separation of the utilities" between South Carolina and North Carolina.

a. Please confirm that the capacity factors calculated in Attachment III (Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study) are based on the average capacity factors for resources sited in North Carolina.

b. If the answer to 7(a) is no, have the Companies performed any analysis of the capacity factors for renewable resources cited solely in North Carolina?

c. Have the Companies performed any estimate of the increased costs to customers if there is an "ultimate separate of the utilities"? If so, please provide that analysis, including a description of the types of costs the Companies would expect to incur and the amount of such costs, if known.

d. Please confirm that the Carbon Plan proposed by the Companies seeks to achieve the carbon reduction goals on a system-wide basis, i.e., including the Companies' South Carolina territories.

e. If the answer to 7(d) is yes, describe all impacts the "ultimate separation of the utilities" would have on the Companies' Carbon Plan proposals.

RESPONSE:

a. The Capacity Factors are based on average capacity factors across DEP and DEC separately. Since DEC and DEP each include both North Carolina and South Carolina within their respective jurisdictions, the solar capacity factors in both DEC and DEP are averages of sites across North Carolina and South Carolina.

b. The Companies have not performed analysis of the capacity factors for renewable resources cited solely in North Carolina.

Responder (parts a and b): Matthew Kalemba, Director, DET Planning & Forecasting

c. The Companies object to this request to the extent it seeks analysis that is subject to the attorney/client and attorney work product privileges. Notwithstanding and without waiving this objection, separation of the utilities, if ultimately deemed necessary, would require consideration of multiple different scenarios and potential options. Legacy assets, new resource plans and ownership, credit and financing impacts, along with required changes to operational functions and enabling infrastructure changes would need to be studied in detail and would be subject to regulatory review and approval from the NCUC, PSCSC and FERC.

Responder: Kendal C. Bowman, Vice President, State and Federal Regulatory Legal Support

d. Yes, the Companies' proposed Carbon Plan seeks to achieve the carbon reduction goals based on continued operation of a dual-state system. Please refer to the Executive Summary page 8, which states, "First and foremost, the Companies are committed to system-wide CO2 emissions reductions, targeting carbon neutrality for their entire system by 2050." Page 8 of the Executive Summary provides further details regarding modeling assumptions and siting of new resources.

Responder: Nathan Gagnon, Principal Planning Analyst

e. As explained in the Carbon Plan (see Executive Summary and Chapter 1), the Companies intend to seek continued alignment between the states. To the extent that continued alignment cannot be achieved, it will be necessary for each state to separately plan to serve its respective retail load. However, the Companies believe that the proposed near-term actions are reasonable and appropriate even in an extreme scenario involving separate state planning. In any event, as explained in the Carbon Plan, the Companies expect to have more clarity in the 2024 Carbon Plan proceeding regarding the extent of state alignment, which can then inform further modification of the Carbon Plan. See also the Companies' response to 1-7(c).

Responder: Kendal C. Bowman, Vice President, State and Federal Regulatory Legal Support

I/A

2020 SESSION

CIGFUR II & III Carolinas Utilities Operations Panel Direct Cross Examination Exhibit 7
Docket No. E-100, Sub 179A

CHAPTER 1193

*An Act to amend and reenact §§ **10.1-1308**, **56-576**, **56-585.1**, **56-585.1:4**, **56-594**, and **56-596.2** of the Code of Virginia and § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017; to amend the Code of Virginia by adding sections numbered **56-585.1:11**, **56-585.5**, and **56-585.6**; and to repeal § **56-585.2** of the Code of Virginia, relating to the regulation of electric utilities; ending carbon dioxide emissions; construction or acquisition of renewable energy facilities; renewable portfolio standards for electric utilities and suppliers; energy efficiency programs and standards; energy storage; net energy metering; third-party power purchase agreements; and the Percentage of Income Payment Program.*

[H 1526]
Approved April 11, 2020

Be it enacted by the General Assembly of Virginia:

1. That §§ **10.1-1308**, **56-576**, **56-585.1**, **56-585.1:4**, **56-594**, and **56-596.2** of the Code of Virginia and § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, are amended and reenacted and that the Code of Virginia is amended by adding sections numbered **56-585.1:11**, **56-585.5**, and **56-585.6** as follows:

§ **10.1-1308**. Regulations.

A. The Board, after having studied air pollution in the various areas of the Commonwealth, its causes, prevention, control and abatement, shall have the power to promulgate regulations, including emergency regulations, abating, controlling and prohibiting air pollution throughout or in any part of the Commonwealth in accordance with the provisions of the Administrative Process Act (§ **2.2-4000** et seq.), except that a description of provisions of any proposed regulation which are more restrictive than applicable federal requirements, together with the reason why the more restrictive provisions are needed, shall be provided to the standing committee of each house of the General Assembly to which matters relating to the content of the regulation are most properly referable. No such regulation shall prohibit the burning of leaves from trees by persons on property where they reside if the local governing body of the county, city or town has enacted an otherwise valid ordinance regulating such burning. The regulations shall not promote or encourage any substantial degradation of present air quality in any air basin or region which has an air quality superior to that stipulated in the regulations. Any regulations adopted by the Board to have general effect in part or all of the Commonwealth shall be filed in accordance with the Virginia Register Act (§ **2.2-4100** et seq.).

B. Any regulation that prohibits the selling of any consumer product shall not restrict the continued sale of the product by retailers of any existing inventories in stock at the time the regulation is promulgated.

C. Any regulation requiring the use of stage 1 vapor recovery equipment at gasoline dispensing facilities may be applicable only in areas that have been designated at any time by the U.S. Environmental Protection Agency as nonattainment for the pollutant ozone. For purposes of this section, gasoline dispensing facility means any site where gasoline is dispensed to motor vehicle tanks from storage tanks.

D. No regulation of the Board shall require permits for the construction or operation of qualified fumigation facilities, as defined in § **10.1-1308.01**.

E. Notwithstanding any other provision of law and no earlier than July 1, 2024, the Board shall adopt regulations to reduce, for the period of 2031 to 2050, the carbon dioxide emissions from any electricity generating unit in the Commonwealth, regardless of fuel type, that serves an electricity generator with a nameplate capacity equal to or greater than 25 megawatts that supplies (i) 10 percent or more of its annual net electrical generation to the electric grid or (ii) more than 15 percent of its annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected (covered unit).

J/A

The Board may establish, implement, and manage an auction program to sell allowances to carry out the purposes of such regulations or may in its discretion utilize an existing multistate trading system.

The Board may utilize its existing regulations to reduce carbon dioxide emissions from electric power generating facilities; however, the regulations shall provide that no allowances be issued for covered units in 2050 or any year beyond 2050. The Board may establish rules for trading, the use of banked allowances, and other auction or market mechanisms as it may find appropriate to control allowance costs and otherwise carry out the purpose of this subsection.

In adopting such regulations, the Board shall consider only the carbon dioxide emissions from the covered units. The Board shall not provide for emission offsetting or netting based on fuel type.

*Regulations adopted by the Board under this subsection shall be subject to the requirements set out in §§ **2.2-4007.03**, **2.2-4007.04**, **2.2-4007.05**, and **2.2-4026** through **2.2-4030** of the Administrative Process Act (§ **2.2-4000** et seq.) and shall be published in the Virginia Register of Regulations.*

§ **56-576**. Definitions.

As used in this chapter:

"Affiliate" means any person that controls, is controlled by, or is under common control with an electric utility.

"Aggregator" means a person that, as an agent or intermediary, (i) offers to purchase, or purchases, electric energy or (ii) offers to arrange for, or arranges for, the purchase of electric energy, for sale to, or on behalf of, two or more retail customers not controlled by or under common control with such person. The following activities shall not, in and of themselves, make a person an aggregator under this chapter: (i) furnishing legal services to two or more retail customers, suppliers or aggregators; (ii) furnishing educational, informational, or analytical services to two or more retail customers, unless direct or indirect compensation for such services is paid by an aggregator or supplier of electric energy; (iii) furnishing educational, informational, or analytical services to two or more suppliers or aggregators; (iv) providing default service under § **56-585**; (v) engaging in activities of a retail electric energy supplier, licensed pursuant to § **56-587**, which are authorized by such supplier's license; and (vi) engaging in actions of a retail customer, in common with one or more other such retail customers, to issue a request for proposal or to negotiate a purchase of electric energy for consumption by such retail customers.

(Expires December 31, 2023) "Business park" means a land development containing a minimum of 100 contiguous acres classified as a Tier 4 site under the Virginia Economic Development Partnership's Business Ready Sites Program that is developed and constructed by an industrial development authority, or a similar political subdivision of the Commonwealth created pursuant to § **15.2-4903** or other act of the General Assembly, in order to promote business development and that is located in an area of the Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury via his delegation of authority to the Internal Revenue Service.

"Combined heat and power" means a method of using waste heat from electrical generation to offset traditional processes, space heating, air conditioning, or refrigeration.

"Commission" means the State Corporation Commission.

"Community in which a majority of the population are people of color" means a U.S. Census tract where more than 50 percent of the population comprises individuals who identify as belonging to one or more of the following groups: Black, African American, Asian, Pacific Islander, Native American, other non-white race, mixed race, Hispanic, Latino, or linguistically isolated.

"Cooperative" means a utility formed under or subject to Chapter 9.1 (§ **56-231.15** et seq.).

"Covered entity" means a provider in the Commonwealth of an electric service not subject to competition but ~~shall~~ *does* not include default service providers.

"Covered transaction" means an acquisition, merger, or consolidation of, or other transaction involving stock, securities, voting interests or assets by which one or more persons obtains control of a covered entity.

I/A

"Curtailment" means inducing retail customers to reduce load during times of peak demand so as to ease the burden on the electrical grid.

"Customer choice" means the opportunity for a retail customer in the Commonwealth to purchase electric energy from any supplier licensed and seeking to sell electric energy to that customer.

"Demand response" means measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

"Distribute," "distributing," or "distribution of" electric energy means the transfer of electric energy through a retail distribution system to a retail customer.

"Distributor" means a person owning, controlling, or operating a retail distribution system to provide electric energy directly to retail customers.

"Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.

"Electric utility" means any person that generates, transmits, or distributes electric energy for use by retail customers in the Commonwealth, including any investor-owned electric utility, cooperative electric utility, or electric utility owned or operated by a municipality.

"Energy efficiency program" means a program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome. Energy efficiency programs may include, but are not limited to, (i) programs that result in improvements in lighting design, heating, ventilation, and air conditioning systems, appliances, building envelopes, and industrial and commercial processes; (ii) measures, such as but not limited to the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems; and (iii) customer engagement programs that result in measurable and verifiable energy savings that lead to efficient use patterns and practices. Energy efficiency programs include demand response, combined heat and power and waste heat recovery, curtailment, or other programs that are designed to reduce electricity consumption so long as they reduce the total amount of electricity that is required for the same process or activity. Utilities shall be authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in this chapter establishes a requirement that an energy efficiency program be implemented on a customer's premises and be connected to a customer's wiring on the customer's side of the inter-connection without the customer's expressed consent.

"Generate," "generating," or "generation of" electric energy means the production of electric energy.

"Generator" means a person owning, controlling, or operating a facility that produces electric energy for sale.

"Historically economically disadvantaged community" means (i) a community in which a majority of the population are people of color or (ii) a low-income geographic area.

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"Incumbent electric utility" means each electric utility in the Commonwealth that, prior to July 1, 1999, supplied electric energy to retail customers located in an exclusive service territory established by the Commission.

"Independent system operator" means a person that may receive or has received, by transfer pursuant to this chapter, any ownership or control of, or any responsibility to operate, all or part of the transmission systems in the Commonwealth.

"In the public interest," for purposes of assessing energy efficiency programs, describes an energy efficiency program if the Commission determines that the net present value of the benefits exceeds the net present value of the costs as determined by not less than any three of the following four tests: (i) the Total Resource Cost Test; (ii) the Utility Cost Test (also referred to as the Program Administrator Test); (iii) the Participant Test; and (iv) the Ratepayer Impact Measure Test. Such determination shall include an analysis of all four tests, and a program or portfolio of programs shall be approved if the net present value of the benefits exceeds the net present value of the costs as determined by not less than any three of the four tests. If the Commission determines that an energy efficiency program or portfolio of programs is not in the public interest, its final order shall include all work product and analysis conducted by the Commission's staff in relation to that program, including testimony relied upon by the Commission's staff, that has bearing upon the Commission's decision. If the Commission reduces the proposed budget for a program or portfolio of programs, its final order shall include an analysis of the impact such budget reduction has upon the cost-effectiveness of such program or portfolio of programs. An order by the Commission (a) finding that a program or portfolio of programs is not in the public interest or (b) reducing the proposed budget for any program or portfolio of programs shall adhere to existing protocols for extraordinarily sensitive information. In addition, an energy efficiency program may be deemed to be "in the public interest" if the program *(1)* provides measurable and verifiable energy savings to low-income customers or elderly customers *or (2) is a pilot program of limited scope, cost, and duration, that is intended to determine whether a new or substantially revised program or technology would be cost-effective.*

"Low-income geographic area" means any locality, or community within a locality, that has a median household income that is not greater than 80 percent of the local median household income, or any area in the Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury via his delegation of authority to the Internal Revenue Service.

"Low-income utility customer" means any person or household whose income is no more than 80 percent of the median income of the locality in which the customer resides. The median income of the locality is determined by the U.S. Department of Housing and Urban Development.

"Measured and verified" means a process determined pursuant to methods accepted for use by utilities and industries to measure, verify, and validate energy savings and peak demand savings. This may include the protocol established by the United States Department of Energy, Office of Federal Energy Management Programs, Measurement and Verification Guidance for Federal Energy Projects, measurement and verification standards developed by the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE), or engineering-based estimates of energy and demand savings associated with specific energy efficiency measures, as determined by the Commission.

"Municipality" means a city, county, town, authority, or other political subdivision of the Commonwealth.

"New underground facilities" means facilities to provide underground distribution service. "New underground facilities" includes underground cables with voltages of 69 kilovolts or less, pad-mounted devices, connections at customer meters, and transition terminations from existing overhead distribution sources.

"Peak-shaving" means measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

"Percentage of Income Payment Program (PIPP) eligible utility customer" means any person or household participating in any of the following public assistance programs: the Supplemental Nutrition Assistance Program, Temporary Assistance for Needy Families, Special Supplemental Nutrition Program for Women, Infants and Children, Virginia Low Income Home Energy Assistance Program, federal Low Income Home Energy Assistance Program, state plan for medical assistance, Medicaid, Housing Choice Voucher Program, or Family Access to Medical Insurance Security Plan.

"Person" means any individual, corporation, partnership, association, company, business, trust, joint venture, or other private legal entity, and the Commonwealth or any municipality.

"Qualified waste heat resource" means (i) exhaust heat or flared gas from an industrial process that does not have, as its primary purpose, the production of electricity and (ii) a pressure drop in any gas for an industrial or commercial process.

"Renewable energy" means energy derived from sunlight, wind, falling water, biomass, sustainable or otherwise, (the definitions of which shall be liberally construed), energy from waste, landfill gas, municipal solid waste, wave motion, tides, and geothermal power, and does not include energy derived from coal, oil, natural gas, or nuclear power. *"*Renewable~~ energy shall~~ *energy"* also~~ include~~ *includes* the proportion of the thermal or electric energy from a facility that results from the co-firing of biomass. *"Renewable energy" does not include waste heat from fossil-fired facilities or electricity generated from pumped storage but includes run-of-river generation from a combined pumped-storage and run-of-river facility.*

"Renewable thermal energy" means the thermal energy output from (i) a renewable-fueled combined heat and power generation facility that is (a) constructed, or renovated and improved, after January 1, 2012, (b) located in the Commonwealth, and (c) utilized in industrial processes other than the combined heat and power generation facility or (ii) a solar energy system, certified to the OG-100 standard of the Solar Ratings and Certification Corporation or an equivalent certification body, that (a) is constructed, or renovated and improved, after January 1, 2013, (b) is located in the Commonwealth, and (c) heats water or air for residential, commercial, institutional, or industrial purposes.

"Renewable thermal energy equivalent" means the electrical equivalent in megawatt hours of renewable thermal energy calculated by dividing (i) the heat content, measured in British thermal units (BTUs), of the renewable thermal energy at the point of transfer to a residential, commercial, institutional, or industrial process by (ii) the standard conversion factor of 3.413 million BTUs per megawatt hour.

"Renovated and improved facility" means a facility the components of which have been upgraded to enhance its operating efficiency.

"Retail customer" means any person that purchases retail electric energy for its own consumption at one or more metering points or nonmetered points of delivery located in the Commonwealth.

"Retail electric energy" means electric energy sold for ultimate consumption to a retail customer.

"Revenue reductions related to energy efficiency programs" means reductions in the collection of total non-fuel revenues, previously authorized by the Commission to be recovered from customers by a utility, that occur due to measured and verified decreased consumption of electricity caused by energy efficiency programs approved by the Commission and implemented by the utility, less the amount by which such non-fuel reductions in total revenues have been mitigated through other program-related factors, including reductions in variable operating expenses.

"Rooftop solar installation" means a distributed electric generation facility, storage facility, or generation and storage facility utilizing energy derived from sunlight, with a rated capacity of not less than 50 kilowatts, that is installed on the roof structure of an incumbent electric utility's commercial or industrial class customer, including host sites on commercial buildings, multifamily residential buildings, school or university buildings, and buildings of a church or religious body.

"Solar energy system" means a system of components that produces heat or electricity, or both, from sunlight.

"Supplier" means any generator, distributor, aggregator, broker, marketer, or other person who offers to sell or sells electric energy to retail customers and is licensed by the Commission to do so, but it does not mean a generator that produces electric energy exclusively for its own consumption or the consumption of an affiliate.

"Supply" or "supplying" electric energy means the sale of or the offer to sell electric energy to a retail customer.

"Total annual energy savings" means (i) the total combined kilowatt-hour savings achieved by electric utility energy efficiency and demand response programs and measures installed in that program year, as well as savings still being achieved by measures and programs implemented in prior years, or (ii) savings attributable to newly installed combined heat and power facilities, including waste heat-to-power facilities, and any associated reduction in transmission line losses, provided that biomass is not a fuel and the total efficiency, including the use of thermal energy, for eligible combined heat and power facilitates must meet or exceed 65 percent and have a nameplate capacity rating of less than 25 megawatts.

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"Transmission of," "transmit," or "transmitting" electric energy means the transfer of electric energy through the Commonwealth's interconnected transmission grid from a generator to either a distributor or a retail customer.

"Transmission system" means those facilities and equipment that are required to provide for the transmission of electric energy.

"Waste heat to power" means a system that generates electricity through the recovery of a qualified waste heat resource.

§ **56-585.1**. Generation, distribution, and transmission rates after capped rates terminate or expire.

A. During the first six months of 2009, the Commission shall, after notice and opportunity for hearing, initiate proceedings to review the rates, terms and conditions for the provision of generation, distribution and transmission services of each investor-owned incumbent electric utility. Such proceedings shall be governed by the provisions of Chapter 10 (§ **56-232** et seq.), except as modified herein. In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average. The peer group of the utility shall be determined in the manner prescribed in subdivision 2 b. The Commission may increase or decrease such combined rate of return by up to 100 basis points based on the generating plant performance, customer service, and operating efficiency of a utility, as compared to nationally recognized standards determined by the Commission to be appropriate for such purposes. In such a proceeding, the Commission shall determine the rates that the utility may charge until such rates are adjusted. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points below the combined rate of return as so determined, it shall be authorized to order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such combined rate of return. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points above the combined rate of return as so determined, it shall be authorized either (i) to order reductions to the utility's rates it finds appropriate, provided that the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than the fair rates of return on common equity applicable to the generation and distribution services; or (ii) to direct that 60 percent of the amount of the utility's earnings that were more than 50 basis points above the fair combined rate of return for calendar year 2008 be credited to customers' bills, in which event such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order and be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates. Commencing in 2011, the Commission, after notice and opportunity for hearing, shall conduct reviews of the rates, terms and conditions for the provision of generation, distribution and transmission services by each investor-owned incumbent electric utility, subject to the following provisions:

1. Rates, terms and conditions for each service shall be reviewed separately on an unbundled basis, and such reviews shall be conducted in a single, combined proceeding. Pursuant to subsection A of § **56-585.1:1**, the Commission shall conduct a review for a Phase I Utility in 2020, utilizing the three successive 12-month test periods beginning January 1, 2017, and ending December 31, 2019. Thereafter, reviews for a Phase I Utility will be on a triennial basis with subsequent proceedings utilizing the three successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. Pursuant to subsection A of § **56-585.1:1**, the Commission shall conduct a review for a Phase II Utility in 2021, utilizing the four successive 12-month test periods beginning January 1, 2017, and ending December 31, 2020, with subsequent reviews on a triennial basis utilizing the three successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. All such reviews occurring after December 31, 2017, shall be referred to as triennial reviews. For purposes of this section, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement.

2. Subject to the provisions of subdivision 6, the fair rate of return on common equity applicable separately to the generation and distribution services of such utility, and for the two such services combined, and for any rate adjustment clauses approved

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under subdivision 5 or 6, shall be determined by the Commission during each such triennial review, as follows:

a. The Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility subject to such triennial review, nor shall the Commission set such return more than 300 basis points higher than such average.

b. In selecting such majority of peer group investor-owned electric utilities, the Commission shall first remove from such group the two utilities within such group that have the lowest reported returns of the group, as well as the two utilities within such group that have the highest reported returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group. In its final order regarding such triennial review, the Commission shall identify the utilities in such peer group it selected for the calculation of such limitation. For purposes of this subdivision, an investor-owned electric utility shall be deemed part of such peer group if (i) its principal operations are conducted in the southeastern United States east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee, (ii) it is a vertically-integrated electric utility providing generation, transmission and distribution services whose facilities and operations are subject to state public utility regulation in the state where its principal operations are conducted, (iii) it had a long-term bond rating assigned by Moody's Investors Service of at least Baa at the end of the most recent test period subject to such triennial review, and (iv) it is not an affiliate of the utility subject to such triennial review.

c. The Commission may, consistent with its precedent for incumbent electric utilities prior to the enactment of Chapters 888 and 933 of the Acts of Assembly of 2007, increase or decrease the utility's combined rate of return based on the Commission's consideration of the utility's performance.

d. In any Current Proceeding, the Commission shall determine whether the Current Return has increased, on a percentage basis, above the Initial Return by more than the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. If so, the Commission may conduct an additional analysis of whether it is in the public interest to utilize such Current Return for the Current Proceeding then pending. A finding of whether the Current Return justifies such additional analysis shall be made without regard to any enhanced rate of return on common equity awarded pursuant to the provisions of subdivision 6. Such additional analysis shall include, but not be limited to, a consideration of overall economic conditions, the level of interest rates and cost of capital with respect to business and industry, in general, as well as electric utilities, the current level of inflation and the utility's cost of goods and services, the effect on the utility's ability to provide adequate service and to attract capital if less than the Current Return were utilized for the Current Proceeding then pending, and such other factors as the Commission may deem relevant. If, as a result of such analysis, the Commission finds that use of the Current Return for the Current Proceeding then pending would not be in the public interest, then the lower limit imposed by subdivision 2 a on the return to be determined by the Commission for such utility shall be calculated, for that Current Proceeding only, by increasing the Initial Return by a percentage at least equal to the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. For purposes of this subdivision:

"Current Proceeding" means any proceeding conducted under any provisions of this subsection that require or authorize the Commission to determine a fair combined rate of return on common equity for a utility and that will be concluded after the date on which the Commission determined the Initial Return for such utility.

"Current Return" means the minimum fair combined rate of return on common equity required for any Current Proceeding by the limitation regarding a utility's peer group specified in subdivision 2 a.

"Initial Return" means the fair combined rate of return on common equity determined for such utility by the Commission on the first occasion after July 1, 2009, under any provision of this subsection pursuant to the provisions of subdivision 2 a.

e. In addition to other considerations, in setting the return on equity within the range allowed by this section, the Commission shall strive to maintain costs of retail electric energy that are cost competitive with costs of retail electric energy provided by the other peer group investor-owned electric utilities.

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f. The determination of such returns shall be made by the Commission on a stand-alone basis, and specifically without regard to any return on common equity or other matters determined with regard to facilities described in subdivision 6.

g. If the combined rate of return on common equity earned by the generation and distribution services is no more than 50 basis points above or below the return as so determined or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, such return is no more than 70 basis points above or below the return as so determined, such combined return shall not be considered either excessive or insufficient, respectively. However, for any test period commencing after December 31, 2012, for a Phase II Utility, and after December 31, 2013, for a Phase I Utility, if the utility has, during the test period or periods under review, earned below the return as so determined, whether or not such combined return is within 70 basis points of the return as so determined, the utility may petition the Commission for approval of an increase in rates in accordance with the provisions of subdivision 8 a as if it had earned more than 70 basis points below a fair combined rate of return, and such proceeding shall otherwise be conducted in accordance with the provisions of this section. The provisions of this subdivision are subject to the provisions of subdivision 8.

h. Any amount of a utility's earnings directed by the Commission to be credited to customers' bills pursuant to this section shall not be considered for the purpose of determining the utility's earnings in any subsequent triennial review.

3. Each such utility shall make a triennial filing by March 31 of every third year, with such filings commencing for a Phase I Utility in 2020, and such filings commencing for a Phase II Utility in 2021, consisting of the schedules contained in the Commission's rules governing utility rate increase applications. Such filing shall encompass the three successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted, except that the filing for a Phase II Utility in 2021 shall encompass the four successive 12-month test periods ending December 31, 2020, and in every such case the filing for each year shall be identified separately and shall be segregated from any other year encompassed by the filing. If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or 9, any rate adjustment clauses previously implemented related to facilities utilizing simple-cycle combustion turbines described in subdivision 6, shall be combined with the utility's costs, revenues and investments until the amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall combine such clauses with the utility's costs, revenues and investments only after it makes its initial determination with regard to necessary rate revisions or credits to customers' bills, and the amounts thereof, but after such clauses are combined as herein specified, they shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future triennial review proceedings. In a triennial filing under this subdivision that does not result in an overall rate change a utility may propose an adjustment to one or more tariffs that are revenue neutral to the utility.

4. (Expires December 31, 2023) The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission; (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member; and (iii) costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park. Upon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service; charges for new and existing transmission facilities, including costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park; administrative charges; and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules.

4. (Effective January 1, 2024) The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission, and (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member. Upon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service, charges for new and existing transmission facilities, administrative charges, and ancillary service charges designed to recover transmission costs,

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shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules.

5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:

a. Incremental costs described in clause (vi) of subsection B of § **56-582** incurred between July 1, 2004, and the expiration or termination of capped rates, if such utility is, as of July 1, 2007, deferring such costs consistent with an order of the Commission entered under clause (vi) of subsection B of § **56-582**. The Commission shall approve such a petition allowing the recovery of such costs that comply with the requirements of clause (vi) of subsection B of § **56-582**;

b. Projected and actual costs for the utility to design and operate fair and effective peak-shaving programs *or pilot programs*. The Commission shall approve such a petition if it finds that the program is in the public interest~~;~~*,* provided that the Commission shall allow the recovery of such costs as it finds are reasonable;

c. Projected and actual costs for the utility to design, implement, and operate energy efficiency programs~~, including a margin to be recovered on operating expenses, which margin for the purposes of this section shall be equal to the general rate of return on common equity determined as described in subdivision 2~~ *or pilot programs*. Any such petition shall include a proposed budget for the design, implementation, and operation of the energy efficiency program*, including anticipated savings from and spending on each program, and the Commission shall grant a final order on such petitions within eight months of initial filing*. The Commission shall only approve such a petition if it finds that the program is in the public interest. If the Commission determines that an energy efficiency program or portfolio of programs is not in the public interest, its final order shall include all work product and analysis conducted by the Commission's staff in relation to that program that has bearing upon the Commission's determination. Such order shall adhere to existing protocols for extraordinarily sensitive information.~~ As part of such cost recovery, the Commission, if requested by the utility, shall allow for the recovery of revenue reductions related to energy efficiency programs. The Commission shall only allow such recovery to the extent that the Commission determines such revenue has not been recovered through margins from incremental off-system sales as defined in § 56-249.6 that are directly attributable to energy efficiency programs.~~

Energy efficiency pilot programs are in the public interest provided that the pilot program is (i) of limited scope, cost, and duration and (ii) intended to determine whether a new or substantially revised program would be cost-effective.

*Prior to January 1, 2022, the Commission shall award a margin for recovery on operating expenses for energy efficiency programs and pilot programs, which margin shall be equal to the general rate of return on common equity determined as described in subdivision 2. Beginning January 1, 2022, and thereafter, if the Commission determines that the utility meets in any year the annual energy efficiency standards set forth in § **56-596.2**, in the following year, the Commission shall award a margin on energy efficiency program operating expenses in that year, to be recovered through a rate adjustment clause, which margin shall be equal to the general rate of return on common equity determined as described in subdivision 2. If the Commission does not approve energy efficiency programs that, in the aggregate, can achieve the annual energy efficiency standards, the Commission shall award a margin on energy efficiency operating expenses in that year for any programs the Commission has approved, to be recovered through a rate adjustment clause under this subdivision, which margin shall equal the general rate of return on common equity determined as described in subdivision 2. Any margin awarded pursuant to this subdivision shall be applied as part of the utility's next rate adjustment clause true-up proceeding. The Commission shall also award an additional 20 basis points for each additional incremental 0.1 percent in annual savings in any year achieved by the utility's energy efficiency programs approved by the Commission pursuant to this subdivision, beyond the annual requirements set forth in § **56-596.2**, provided that the total performance incentive awarded in any year shall not exceed 10 percent of that utility's total energy efficiency program spending in that same year.*

*The Commission shall annually monitor and report to the General Assembly the performance of all programs approved pursuant to this subdivision, including each utility's compliance with the total annual savings required by § **56-596.2**, as well as the annual and lifecycle net and gross energy and capacity savings, related emissions reductions, and other quantifiable benefits of each program; total customer bill savings that the programs produce; utility spending on each program, including any associated administrative costs; and each utility's avoided costs and cost-effectiveness results.*

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*Notwithstanding any other provision of law, unless the Commission finds in its discretion and after consideration of all in-state and regional transmission entity resources that there is a threat to the reliability or security of electric service to the utility's customers, the Commission shall not approve construction of any new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § **56-596.2** and the Commission finds that supply-side resources are more cost-effective than demand-side or energy storage resources.*

~~None of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, shall be assigned to any large general service customer. A~~ *As used in this subdivision, "*large general service customer~~ is~~*" means* a customer that has a verifiable history of having used more than~~ 500 kilowatts~~ *one megawatt* of demand from a single~~ meter of delivery~~ *site*.

*Large general service customers shall be exempt from requirements that they participate in energy efficiency programs if the Commission finds that the large general service customer has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with industry standards and other regulatory criteria stated in this section. The Commission shall, no later than June 30, 2021, adopt rules or regulations (a) establishing the process for large general service customers to apply for such an exemption, (b) establishing the administrative procedures by which eligible customers will notify the utility, and (c) defining the standard criteria that shall be satisfied by an applicant in order to notify the utility, including means of evaluation measurement and verification and confidentiality requirements. At a minimum, such rules and regulations shall require that each exempted large general service customer certify to the utility and Commission that its implemented energy efficiency programs have delivered measured and verified savings within the prior five years. In adopting such rules or regulations, the Commission shall also specify the timing as to when a utility shall accept and act on such notice, taking into consideration the utility's integrated resource planning process, as well as its administration of energy efficiency programs that are approved for cost recovery by the Commission. Savings from large general service customers shall be accounted for in utility reporting in the standards in § **56-596.2**.*

The notice of nonparticipation by a large general service customer shall be for the duration of the service life of the customer's energy efficiency measures. The Commission may on its own motion initiate steps necessary to verify such nonparticipant's achievement of energy efficiency if the Commission has a body of evidence that the nonparticipant has knowingly misrepresented its energy efficiency achievement.

A utility shall not charge such large general service customer~~, as defined by the Commission,~~ for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth;

d. Projected and actual costs of~~ participation in a~~ *compliance with* renewable energy portfolio standard~~ program~~ *requirements* pursuant to §~~ 56-585.2~~ *56-585.5* that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs *incurred* as~~ are provided for in a program approved pursuant to~~ *required by* §~~ 56-585.2~~ *56-585.5, provided that the Commission does not otherwise find such costs were unreasonably or imprudently incurred*;

e. Projected and actual costs of projects that the Commission finds to be necessary *to mitigate impacts to marine life caused by construction of offshore wind generating facilities, as described in § **56-585.1:11**, or* to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations*, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions*. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations; and

f. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission that accelerate the vegetation management of distribution rights-of-way. No costs shall be allocated to or recovered from customers that are served within the large general service rate classes for a Phase II Utility or that are served at subtransmission or transmission voltage, or take delivery at a substation served from subtransmission or transmission voltage, for a Phase I Utility.

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Any rate adjustment clause approved under subdivision 5 c by the Commission shall remain in effect until the utility exhausts the approved budget for the energy efficiency program. The Commission shall have the authority to determine the duration or amortization period for any other rate adjustment clause approved under this subdivision.

6. To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of (i) a coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth as described in § **15.2-6002**, regardless of whether such facility is located within or without the utility's service territory, (ii) one or more other generation facilities, (iii) one or more major unit modifications of generation facilities, including the costs of any system or equipment upgrade, system or equipment replacement, or other cost reasonably appropriate to extend the combined operating license for or the operating life of one or more generation facilities utilizing nuclear power, (iv) one or more new underground facilities to replace one or more existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth, (v) one or more pumped hydroelectricity generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the Commonwealth as described in § **15.2-6002**, regardless of whether such facility is located within or without the utility's service territory, or (vi) one or more electric distribution grid transformation projects; however, subject to the provisions of the following sentence, the utility shall not file a petition under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental increase in the level of investments associated with such a petition that exceeds five percent of such utility's distribution rate base, as such rate base was determined for the most recently ended 12-month test period in the utility's latest review proceeding conducted pursuant to subdivision 3 and concluded by final order of the Commission prior to the date of filing of such petition under clause (iv). In all proceedings regarding petitions filed under clause (iv) or (vi), the level of investments approved for recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously approved for recovery in prior proceedings under clause (iv) or (vi), as applicable. As of December 1, 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs associated with conversions of overhead distribution facilities to underground facilities that have been previously approved or are pending approval by the Commission through a petition by the utility under this subdivision. Such a petition concerning facilities described in clause (ii) that utilize nuclear power, facilities described in clause (ii) that are coal-fueled and will be built by a Phase I Utility, or facilities described in clause (i) may also be filed before the expiration or termination of capped rates. A utility that constructs or makes modifications to any such facility, or purchases any facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, shall have the right to recover the costs of the facility, as accrued against income, through its rates, including projected construction work in progress, and any associated allowance for funds used during construction, planning, development and construction or acquisition costs, life-cycle costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs of infrastructure associated therewith, plus, as an incentive to undertake such projects, an enhanced rate of return on common equity calculated as specified below; however, in determining the amounts recoverable under a rate adjustment clause for new underground facilities, the Commission shall not consider, or increase or reduce such amounts recoverable because of (a) the operation and maintenance costs attributable to either the overhead distribution facilities being replaced or the new underground facilities or (b) any other costs attributable to the overhead distribution facilities being replaced. Notwithstanding the preceding sentence, the costs described in clauses (a) and (b) thereof shall remain eligible for recovery from customers through the utility's base rates for distribution service. A utility filing a petition for approval to construct or purchase a facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses may propose a rate adjustment clause based on a market index in lieu of a cost of service model for such facility. A utility seeking approval to construct or purchase a generating facility ~~described in clause (i) or (ii)~~ *that emits carbon dioxide* shall demonstrate that it has *already met the energy savings goals identified in § **56-596.2** and that the identified need cannot be met more affordably through the deployment or utilization of demand-side resources or energy storage resources and that it has* considered and weighed alternative options, including third-party market alternatives, in its selection process.

The costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes

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goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities are classified by the utility as plant in service. *In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The Commission shall ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities. The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation.*

Such enhanced rate of return on common equity shall be applied to allowance for funds used during construction and to construction work in progress during the construction phase of the facility and shall thereafter be applied to the entire facility during the first portion of the service life of the facility. The first portion of the service life shall be as specified in the table below; however, the Commission shall determine the duration of the first portion of the service life of any facility, within the range specified in the table below, which determination shall be consistent with the public interest and shall reflect the Commission's determinations regarding how critical the facility may be in meeting the energy needs of the citizens of the Commonwealth and the risks involved in the development of the facility. After the first portion of the service life of the facility is concluded, the utility's general rate of return shall be applied to such facility for the remainder of its service life. As used herein, the service life of the facility shall be deemed to begin on the date a facility constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities or new electric distribution grid transformation projects are classified by the utility as plant in service, and such service life shall be deemed equal in years to the life of that facility as used to calculate the utility's depreciation expense. Such enhanced rate of return on common equity shall be calculated by adding the basis points specified in the table below to the utility's general rate of return, and such enhanced rate of return shall apply only to the facility that is the subject of such rate adjustment clause. Allowance for funds used during construction shall be calculated for any such facility utilizing the utility's actual capital structure and overall cost of capital, including an enhanced rate of return on common equity as determined pursuant to this subdivision, until such construction work in progress is included in rates. The construction of any facility described in clause (i) or (v) is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. The construction or purchase by a utility of one or more generation facilities with at least one megawatt of generating capacity, and with an aggregate rated capacity that does not exceed ~~5,000~~ *16,100* megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of ~~50~~ *100* megawatts, that use energy derived from sunlight or from *onshore* wind and are located in the Commonwealth or off the Commonwealth's Atlantic shoreline, regardless of whether any of such facilities are located within or without the utility's service territory, is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. A utility may enter into short-term or long-term power purchase contracts for the power derived from sunlight generated by such generation facility prior to purchasing the generation facility. The replacement of any subset of a utility's existing overhead distribution tap lines that have, in the aggregate, an average of nine or more total unplanned outage events-per-mile over a preceding 10-year period with new underground facilities in order to improve electric service reliability is in the public interest. In determining whether to approve petitions for rate adjustment clauses for such new underground facilities that meet this criteria, and in determining the level of costs to be recovered thereunder, the Commission shall liberally construe the provisions of this title.

The conversion of any such facilities on or after September 1, 2016, is deemed to provide local and system-wide benefits and to be cost beneficial, and the costs associated with such new underground facilities are deemed to be reasonably and prudently incurred and, notwithstanding the provisions of subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision, provided that the total costs associated with the replacement of any subset of existing overhead distribution tap lines proposed by the utility with new underground facilities, exclusive of financing costs, shall not exceed an average cost per customer of $20,000, with such customers, including those served directly by or downline of the tap lines proposed for conversion, and, further, such total costs shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of $750,000. A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation

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projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d. The Commission's final order regarding any such petition for approval of an electric distribution grid transformation plan shall be entered by the Commission not more than six months after the date of filing such petition. The Commission shall likewise enter its final order with respect to any petition by a utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived from sunlight, pursuant to subsection D of § **56-580**, within six months after the date of filing such petition. The basis points to be added to the utility's general rate of return to calculate the enhanced rate of return on common equity, and the first portion of that facility's service life to which such enhanced rate of return shall be applied, shall vary by type of facility, as specified in the following table:

Type of Generation Facility	Basis Points	First Portion of Service Life
Nuclear-powered	200	Between 12 and 25 years
Carbon capture compatible, clean-coal powered	200	Between 10 and 20 years
Renewable powered, other than landfill gas powered	200	Between 5 and 15 years
Coalbed methane gas powered	150	Between 5 and 15 years
Landfill gas powered	200	Between 5 and 15 years
Conventional coal or combined-cycle combustion turbine	100	Between 10 and 20 years

~~For generating facilities other than those utilizing nuclear power constructed pursuant to clause (ii) or those utilizing energy derived from offshore wind, as of July 1, 2013, only~~ *Only* those facilities as to which a rate adjustment clause under this subdivision has been previously approved by the Commission, or as to which a petition for approval of such rate adjustment clause was filed with the Commission, on or before January 1, 2013, shall be entitled to the enhanced rate of return on common equity as specified in the above table during the construction phase of the facility and the approved first portion of its service life.

~~For generating facilities within the Commonwealth utilizing nuclear power or those utilizing energy derived from offshore wind projects located in waters off the Commonwealth's Atlantic shoreline, such facilities shall continue to be eligible for an enhanced rate of return on common equity during the construction phase of the facility and the approved first portion of its service life of between 12 and 25 years in the case of a facility utilizing nuclear power and for a service life of between 5 and 15 years in the case of a facility utilizing energy derived from offshore wind, provided, however, that, as of July 1, 2013, the enhanced return for such facilities constructed pursuant to clause (ii) shall be 100 basis points, which shall be added to the utility's general rate of return as determined under subdivision 2.~~ Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through

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existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014. Thirty percent of all costs of ~~such~~ a facility utilizing energy derived from offshore wind that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014.

~~In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, consistent with § 56-598, planning and development activities for a new nuclear generation facility or facilities are in the public interest.~~

In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, consistent with § **56-598**, planning and development activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore or offshore wind are in the public interest.

~~Construction~~ *Notwithstanding any provision of Chapter 296 of the Acts of Assembly of 2018, construction*, purchasing, or leasing activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from *onshore* wind with an aggregate capacity of ~~5,000~~ *16,100* megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of ~~50~~ *100* megawatts, together with ~~a new test or demonstration project for~~ a utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than ~~16~~ *3,000* megawatts, are in the public interest. To the extent that a utility elects to recover the costs of any such new generation facility or facilities through its rates for generation and distribution services and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (ii), the Commission shall, upon the request of the utility in a triennial review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding pursuant to subsection D of § **56-580** or in a triennial review proceeding.

Electric distribution grid transformation projects are in the public interest. To the extent that a utility elects to recover the costs of such electric distribution grid transformation projects through its rates for generation and distribution services, and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (vi), the Commission shall, upon the request of the utility in a triennial review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding for approval of a plan for electric distribution grid transformation projects pursuant to subdivision 6 or in a triennial review proceeding.

Neither generation facilities described in clause (ii) that utilize simple-cycle combustion turbines nor new underground facilities shall receive an enhanced rate of return on common equity as described herein, but instead shall receive the utility's general rate of return during the construction phase of the facility and, thereafter, for the entire service life of the facility. No rate adjustment clause for new underground facilities shall allocate costs to, or provide for the recovery of costs from, customers that are served within the large power service rate class for a Phase I Utility and the large general service rate classes for a Phase II Utility. New underground facilities are hereby declared to be ordinary extensions or improvements in the usual course of business under the provisions of § **56-265.2**.

As used in this subdivision, a generation facility is (1) "coalbed methane gas powered" if the facility is fired at least 50 percent by coalbed methane gas, as such term is defined in § **45.1-361.1**, produced from wells located in the Commonwealth, and (2) "landfill gas powered" if the facility is fired by methane or other combustible gas produced by the anaerobic digestion or decomposition of biodegradable materials in a solid waste management facility licensed by the Waste Management Board. A landfill gas powered facility includes, in addition to the generation facility itself, the equipment used in collecting, drying, treating, and compressing the landfill gas and in transmitting the landfill gas from the solid waste management facility where it is collected to the generation facility where it is combusted.

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For purposes of this subdivision, "general rate of return" means the fair combined rate of return on common equity as it is determined by the Commission for such utility pursuant to subdivision 2.

Notwithstanding any other provision of this subdivision, if the Commission finds during the triennial review conducted for a Phase II Utility in 2021 that such utility has not filed applications for all necessary federal and state regulatory approvals to construct one or more nuclear-powered or coal-fueled generation facilities that would add a total capacity of at least 1500 megawatts to the amount of the utility's generating resources as such resources existed on July 1, 2007, or that, if all such approvals have been received, that the utility has not made reasonable and good faith efforts to construct one or more such facilities that will provide such additional total capacity within a reasonable time after obtaining such approvals, then the Commission, if it finds it in the public interest, may reduce on a prospective basis any enhanced rate of return on common equity previously applied to any such facility to no less than the general rate of return for such utility and may apply no less than the utility's general rate of return to any such facility for which the utility seeks approval in the future under this subdivision.

Notwithstanding any other provision of this subdivision, if a Phase II utility obtains approval from the Commission of a rate adjustment clause pursuant to subdivision 6 associated with a test or demonstration project involving a generation facility utilizing energy from offshore wind, and such utility has not, as of July 1, 2023, commenced construction as defined for federal income tax purposes of an offshore wind generation facility or facilities with a minimum aggregate capacity of 250 megawatts, then the Commission, if it finds it in the public interest, may direct that the costs associated with any such rate adjustment clause involving said test or demonstration project shall thereafter no longer be recovered through a rate adjustment clause pursuant to subdivision 6 and shall instead be recovered through the utility's rates for generation and distribution services, with no change in such rates for generation and distribution services as a result of the combination of such costs with the other costs, revenues, and investments included in the utility's rates for generation and distribution services. Any such costs shall remain combined with the utility's other costs, revenues, and investments included in its rates for generation and distribution services until such costs are fully recovered.

7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs prudently incurred after the expiration or termination of capped rates related to other matters described in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped rates, provided, however, that no provision of this act shall affect the rights of any parties with respect to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset for regulatory accounting and ratemaking purposes under which it shall defer its operation and maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant and (ii) other work at such plant normally performed during a refueling outage. The utility shall amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning with the month in which such plant resumes operation after such refueling. The refueling cycle shall be the applicable period of time between planned refueling outages for such plant. As of January 1, 2014, such amortized costs are a component of base rates, recoverable in base rates only ratably over the refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with respect to triennial filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to § **56-245** or the Commission's rules governing utility rate increase applications as provided in subsection B. This provision shall not be deemed to change or reset base rates.

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The Commission's final order regarding any petition filed pursuant to subdivision 4, 5, or 6 shall be entered not more than three months, eight months, and nine months, respectively, after the date of filing of such petition. If such petition is approved, the order shall direct that the applicable rate adjustment clause be applied to customers' bills not more than 60 days after the date of the order, or upon the expiration or termination of capped rates, whichever is later.

8. In any triennial review proceeding, for the purposes of reviewing earnings on the utility's rates for generation and distribution services, the following utility generation and distribution costs not proposed for recovery under any other subdivision of this subsection, as recorded per books by the utility for financial reporting purposes and accrued against income, shall be attributed to the test periods under review and deemed fully recovered in the period recorded: costs associated with asset impairments related to early retirement determinations made by the utility for utility generation facilities fueled by coal, natural gas, or oil or for automated meter reading electric distribution service meters; costs associated with projects necessary to comply with state or federal environmental laws, regulations, or judicial or administrative orders relating to coal combustion by-product management that the utility does not petition to recover through a rate adjustment clause pursuant to subdivision 5 e; costs associated with severe weather events; and costs associated with natural disasters. Such costs shall be deemed to have been recovered from customers through rates for generation and distribution services in effect during the test periods under review unless such costs, individually or in the aggregate, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, result in the utility's earned return on its generation and distribution services for the combined test periods under review to fall more than 50 basis points below the fair combined rate of return authorized under subdivision 2 for such periods or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to fall more than 70 basis points below the fair combined rate of return authorized under subdivision 2 for such periods. In such cases, the Commission shall, in such triennial review proceeding, authorize deferred recovery of such costs and allow the utility to amortize and recover such deferred costs over future periods as determined by the Commission. The aggregate amount of such deferred costs shall not exceed an amount that would, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, cause the utility's earned return on its generation and distribution services to exceed the fair rate of return authorized under subdivision 2, less 50 basis points, for the combined test periods under review or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to exceed the fair rate of return authorized under subdivision 2 less 70 basis points. Nothing in this section shall limit the Commission's authority, pursuant to the provisions of Chapter 10 (§ **56-232** et seq.), including specifically § **56-235.2**, following the review of combined test period earnings of the utility in a triennial review, for normalization of nonrecurring test period costs and annualized adjustments for future costs, in determining any appropriate increase or decrease in the utility's rates for generation and distribution services pursuant to subdivision 8 a or 8 c.

If the Commission determines as a result of such triennial review that:

a. ~~The~~ *Revenue reductions related to energy efficiency measures or programs approved and deployed since the utility's previous triennial review have caused the utility, as verified by the Commission, during the test period or periods under review, considered as a whole, to earn more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates for generation and distribution services necessary to recover such revenue reductions. If the Commission finds, for reasons other than revenue reductions related to energy efficiency measures, that the* utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return, using the most recently ended 12-month test period as the basis for determining the amount of the rate increase necessary. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, the Commission may not order a rate increase, and in all triennial reviews of a Phase I or Phase II utility, the Commission may not order such rate increase unless it finds that the resulting rates are necessary to provide the utility with the opportunity to fully recover its costs of providing its

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services and to earn not less than a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate increase under the standards of this sentence, and the amount thereof; and provided that, solely in connection with making its determination concerning the necessity for such a rate increase or the amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1, 2028, exclude from this most recently ended 12-month test period any remaining investment levels associated with a prior customer credit reinvestment offset pursuant to subdivision d.

b. The utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall, subject to the provisions of subdivisions 8 d and 9, direct that 60 percent of the amount of such earnings that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, that 70 percent of the amount of such earnings that were more than 70 basis points, above such fair combined rate of return for the test period or periods under review, considered as a whole, shall be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates; or

c. In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after January 1, 2021, for a Phase II Utility in which the utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matter determined with respect to facilities described in subdivision 6, and the combined aggregate level of capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test periods under review in that triennial review proceeding in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and in electric distribution grid transformation projects, as determined pursuant to subdivision 8 d, does not equal or exceed 100 percent of the earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the combined test periods under review in that triennial review proceeding, the Commission shall, subject to the provisions of subdivision 9 and in addition to the actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, any reduction to the utility's rates ordered by the Commission pursuant to this subdivision shall not exceed $50 million in annual revenues, with any reduction allocated to the utility's rates for generation services, and in each triennial review of a Phase I or Phase II Utility, the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate reduction under the standards of this sentence, and the amount thereof; and

d. (Expires July 1, 2028) In any triennial review proceeding conducted after December 31, 2017, upon the request of the utility, the Commission shall determine, prior to directing that 70 percent of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the test period or periods under review be credited to customer bills pursuant to subdivision 8 b, the aggregate level of prior capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test period or periods under review in both (i) new utility-owned generation facilities utilizing energy derived from sunlight, or from onshore or offshore wind, and (ii) electric distribution grid transformation projects, as determined by the utility's plant in service and construction work in progress balances related to such investments as recorded per books by the utility for financial reporting purposes as of the end of the most recent test

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period under review. Any such combined capital investment amounts shall offset any customer bill credit amounts, on a dollar for dollar basis, up to the aggregate level of invested or committed capital under clauses (i) and (ii). The aggregate level of qualifying invested or committed capital under clauses (i) and (ii) is referred to in this subdivision as the customer credit reinvestment offset, which offsets the customer bill credit amount that the utility has invested or will invest in new solar or wind generation facilities or electric distribution grid transformation projects for the benefit of customers, in amounts up to 100 percent of earnings that are more than 70 basis points above the utility's fair rate of return on its generation and distribution services, and thereby reduce or eliminate otherwise incremental rate adjustment clause charges and increases to customer bills, which is deemed to be in the public interest. If 100 percent of the amount of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services, as determined in subdivision 2, exceeds the aggregate level of invested capital in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and electric distribution grid transformation projects, as provided in clauses (i) and (ii), during the test period or periods under review, then 70 percent of the amount of such excess shall be credited to customer bills as provided in subdivision 8 b in connection with the triennial review proceeding. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is the subject of any customer credit reinvestment offset pursuant to this subdivision shall not thereafter be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall not thereafter be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 and shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is not the subject of any customer credit reinvestment offset pursuant to this subdivision may be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 until such costs are fully recovered, and if such costs are recovered through the utility's rates for generation and distribution services, they shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. Only the portion of such costs of new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that has not been included in any customer credit reinvestment offset pursuant to this subdivision, and not otherwise recovered through the utility's rates for generation and distribution services, may be the subject of a rate adjustment clause petition by the utility pursuant to subdivision 6.

The Commission's final order regarding such triennial review shall be entered not more than eight months after the date of filing, and any revisions in rates or credits so ordered shall take effect not more than 60 days after the date of the order. The fair combined rate of return on common equity determined pursuant to subdivision 2 in such triennial review shall apply, for purposes of reviewing the utility's earnings on its rates for generation and distribution services, to the entire three successive 12-month test periods ending December 31 immediately preceding the year of the utility's subsequent triennial review filing under subdivision 3 and shall apply to applicable rate adjustment clauses under subdivisions 5 and 6 prospectively from the date the Commission's final order in the triennial review proceeding, utilizing rate adjustment clause true-up protocols as the Commission in its discretion may determine.

9. If, as a result of a triennial review required under this subsection and conducted with respect to any test period or periods under review ending later than December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, under review ending later than December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), the Commission finds, with respect to such test period or periods considered as a whole, that (i) any utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, and (ii) the total aggregate regulated rates of such utility at the end of the most recently ended 12-month test period exceeded the annual increases in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, compounded annually, when compared to the total aggregate regulated rates of such utility as determined pursuant to the review conducted for the base period, the Commission shall, unless it finds that such action is not in the public interest or that the provisions of subdivisions 8 b and c are more consistent with the public interest, direct that any or all earnings for such test period or periods under review, considered as a whole that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31,

2013, I/A for a Phase I Utility, more than 70 basis points, above such fair combined rate of return shall be credited to customers' bills, in lieu of the provisions of subdivisions 8 b and c, provided that no credits shall be provided pursuant to this subdivision in connection with any triennial review unless such bill credits would be payable pursuant to the provisions of subdivision 8 d, and any credits under this subdivision shall be calculated net of any customer credit reinvestment offset amounts under subdivision 8 d. Any such credits shall be amortized and allocated among customer classes in the manner provided by subdivision 8 b. For purposes of this subdivision:

"Base period" means (i) the test period ending December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, the test period ending December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), or (ii) the most recent test period with respect to which credits have been applied to customers' bills under the provisions of this subdivision, whichever is later.

"Total aggregate regulated rates" shall include: (i) fuel tariffs approved pursuant to § **56-249.6**, except for any increases in fuel tariffs deferred by the Commission for recovery in periods after December 31, 2010, pursuant to the provisions of clause (ii) of subsection C of § **56-249.6**; (ii) rate adjustment clauses implemented pursuant to subdivision 4 or 5; (iii) revisions to the utility's rates pursuant to subdivision 8 a; (iv) revisions to the utility's rates pursuant to the Commission's rules governing utility rate increase applications, as permitted by subsection B, occurring after July 1, 2009; and (v) base rates in effect as of July 1, 2009.

10. For purposes of this section, the Commission shall regulate the rates, terms and conditions of any utility subject to this section on a stand-alone basis utilizing the actual end-of-test period capital structure and cost of capital of such utility, excluding any debt associated with securitized bonds that are the obligation of non-Virginia jurisdictional customers, unless the Commission finds that the debt to equity ratio of such capital structure is unreasonable for such utility, in which case the Commission may utilize a debt to equity ratio that it finds to be reasonable for such utility in determining any rate adjustment pursuant to subdivisions 8 a and c, and without regard to the cost of capital, capital structure, revenues, expenses or investments of any other entity with which such utility may be affiliated. In particular, and without limitation, the Commission shall determine the federal and state income tax costs for any such utility that is part of a publicly traded, consolidated group as follows: (i) such utility's apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.

B. Nothing in this section shall preclude an investor-owned incumbent electric utility from applying for an increase in rates pursuant to § **56-245** or the Commission's rules governing utility rate increase applications; however, in any such filing, a fair rate of return on common equity shall be determined pursuant to subdivision A 2. Nothing in this section shall preclude such utility's recovery of fuel and purchased power costs as provided in § **56-249.6**.

C. Except as otherwise provided in this section, the Commission shall exercise authority over the rates, terms and conditions of investor-owned incumbent electric utilities for the provision of generation, transmission and distribution services to retail customers in the Commonwealth pursuant to the provisions of Chapter 10 (§ **56-232** et seq.), including specifically § **56-235.2**.

D. The Commission may determine, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding. A determination of the Commission regarding the reasonableness or prudence of any such cost shall be consistent with the Commission's authority to determine the reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ **56-232** et seq.). In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Energy Policy set forth in §§ **67-101** and **67-102**, and shall also consider whether the costs of such resources is likely to result in unreasonable increases in rates paid by customers.

E. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

§ **56-585.1:4**. Development of solar and wind generation capacity and energy storage capacity in the Commonwealth.

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A. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of at least one megawatt and having in the aggregate a rated capacity that does not exceed 5,000 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

B. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of less than one megawatt, including rooftop solar installations with a capacity of not less than 50 kilowatts, and having in the aggregate a rated capacity that does not exceed 500 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

C. The aggregate cap of 5,000 megawatts of rated capacity described in clause (i) of subsection A and the aggregate cap of 500 megawatts of rated capacity described in clause (i) of subsection B are separate and independent from each other. The capacity of facilities in subsection B shall not be counted in determining the capacity of facilities in subsection A, and the capacity of facilities in subsection A shall not be counted in determining the capacity of facilities in subsection B.

D. Twenty-five percent of the solar generation capacity placed in service on or after July 1, 2018, located in the Commonwealth, and found to be in the public interest pursuant to subsection A or B shall be from the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities owned by persons other than a public utility. The remainder shall be construction or purchase by a public utility of one or more solar generation facilities located in the Commonwealth. All of the solar generation capacity located in the Commonwealth and found to be in the public interest pursuant to subsection A or B shall be subject to competitive procurement, provided that a public utility may select solar generation capacity without regard to whether such selection satisfies price criteria if the selection of the solar generating capacity materially advances non-price criteria, including favoring geographic distribution of generating capacity, areas of higher employment, or regional economic development, if such non-price solar generating capacity selected does not exceed 25 percent of the utility's solar generating capacity.

E. Construction, purchasing, or leasing activities for a test or demonstration project for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 16 megawatts are in the public interest.

F. *Prior to January 1, 2035, (i) the construction by a public utility of one or more energy storage facilities located in the Commonwealth, having in the aggregate a rated capacity that does not exceed 2,700 megawatts, or (ii) the purchase by a public utility of energy storage facilities described in clause (i) owned by persons other than a public utility or the capacity from such facilities is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.*

G. At least 35 percent of the energy storage capacity placed in service on or after July 1, 2020, located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be from the purchase by a public utility of energy storage facilities owned by persons other than a public utility or the capacity from such facilities. All of the energy storage facilities located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be subject to competitive procurement, provided that a public utility may select energy storage facilities without regard to whether such selection satisfies price criteria if the selection of the energy storage facilities materially advances non-price criteria, including favoring geographic distribution of generating facilities, areas of higher employment, or regional economic development, if such energy storage facilities selected for the advancement of non-price criteria do not exceed 25 percent of the utility's energy storage capacity.

H. A utility may elect to petition the Commission, outside of a triennial review proceeding conducted pursuant to § **56-585.1**, at any time for a prudency determination with respect to the construction or purchase by the utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic Shoreline or the purchase by the utility of energy, capacity, and environmental attributes from solar or wind facilities owned by persons other than the utility. The

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Commission's final order regarding any such petition shall be entered by the Commission not more than three months after the date of the filing of such petition.

*§ **56-585.1:11**. Development of offshore wind capacity.*

A. As used in this section:

"Advanced clean energy buyer" means a commercial or industrial customer of a Phase II Utility, irrespective of generation supplier, (i) with an aggregate load over 100 megawatts; (ii) with an aggregate amount of at least 200 megawatts of solar or wind energy supply under contract with a term of 10 years or more from facilities located within the Commonwealth by January 1, 2024; and (iii) that directly procures from the utility the electric supply and environmental attributes of the offshore wind facility associated with the lesser of 50 megawatts of nameplate capacity or 15 percent of the commercial or industrial customer's annual peak demand for a contract period of 15 years.

"Aggregate load" means the combined electrical load associated with selected accounts of an advanced clean energy buyer with the same legal entity name as, or in the names of affiliated entities that control, are controlled by, or are under common control of, such legal entity or are the names of affiliated entities under a common parent.

"Control" means the legal right, directly or indirectly, to direct or cause the direction of the management, actions, or policies of an affiliated entity, whether through the ability to exercise voting power, by contract, or otherwise. "Control" does not include control of an entity through a franchise or similar contractual agreement.

"Qualifying large general service customer" means a customer of a Phase II Utility, irrespective of general supplier, (i) whose peak demand during the most recent calendar year exceeded five megawatts and (ii) that contracts with the utility to directly procure electric supply and environmental attributes associated with the offshore wind facility in amounts commensurate with the customer's electric usage for a contract period of 15 years or more.

B. In order to meet the Commonwealth's clean energy goals, prior to December 31, 2034, the construction or purchase by a public utility of one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth, with an aggregate capacity of up to 5,200 megawatts, is in the public interest and the Commission shall so find, provided that no customers of the utility shall be responsible for costs of any such facility in a proportion greater than the utility's share of the facility.

C. 1. Pursuant to subsection B, construction by a Phase II Utility of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline, with an aggregate rated capacity of not less than 2,500 megawatts and not more than 3,000 megawatts, along with electrical transmission or distribution facilities associated therewith for interconnection is in the public interest. In acting upon any request for cost recovery by a Phase II Utility for costs associated with such a facility, the Commission shall determine the reasonableness and prudence of any such costs, provided that such costs shall be presumed to be reasonably and prudently incurred if the Commission determines that (i) the utility has complied with the competitive solicitation and procurement requirements pursuant to subsection E; (ii) the project's projected total levelized cost of energy, including any tax credit, on a cost per megawatt hour basis, inclusive of the costs of transmission and distribution facilities associated with the facility's interconnection, does not exceed 1.4 times the comparable cost, on an unweighted average basis, of a conventional simple cycle combustion turbine generating facility as estimated by the U.S. Energy Information Administration in its Annual Energy Outlook 2019; and (iii) the utility has commenced construction of such facilities for U.S. income taxation purposes prior to January 1, 2024, or has a plan for such facility or facilities to be in service prior to January 1, 2028. The Commission shall disallow costs, or any portion thereof, only if they are otherwise unreasonably and imprudently incurred. In its review, the Commission shall give due consideration to (a) the Commonwealth's renewable portfolio standards and carbon reduction requirements, (b) the promotion of new renewable generation resources, and (c) the economic development benefits of the project for the Commonwealth, including capital investments and job creation.

*2. Notwithstanding the provisions of § **56-585.1**, the Commission shall not grant an enhanced rate of return to a Phase II Utility for the construction of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline pursuant to this section.*

*3. Any such costs proposed for recovery through a rate adjustment clause pursuant to subdivision A 6 of § **56-585.1** shall be allocated to all customers of the utility in the Commonwealth as a non-bypassable charge, regardless of the generation supplier of any such customer, other than (i) PIPP eligible utility customers, (ii) advanced clean energy buyers, and (iii) qualifying large general service customers. No electric cooperative customer of the utility shall be assigned, nor shall the utility collect from any such cooperative, any of the costs of such facilities, including electrical transmission or distribution facilities associated therewith for interconnection. The Commission may promulgate such rules, regulations, or other directives necessary to administer the eligibility for these exemptions.*

*4. The Commission shall permit a portion of the nameplate capacity of any such facility, in the aggregate, to be allocated to (i) advanced clean energy buyers or (ii) qualifying large general service customers, provided that no more than 10 percent of the offshore wind facility's capacity is allocated to qualifying large general service customers. A Phase II Utility shall petition the Commission for approval of a special contract with any advanced clean energy buyer, or any special rate applicable to qualifying large general service customers, pursuant to § **56-235.2**, no later than 15 months prior to the projected commercial operation date of the facility, and all customer enrollments associated with such special contracts or rates shall be completed prior to commercial operation of the facility. Any such special contract or rate may include provisions for levelized rates of service over the duration of the customer's contracted agreement with the utility, and the Commission shall determine that such special contract or rate is designed to hold nonparticipating customers harmless over its term in connection with any petition for approval by the utility. The utility may petition for approval of such special contracts or rates in connection with any petition for approval of a rate adjustment clause pursuant to subdivision A 6 of § **56-585.1** to recover the costs of the facility, and the Commission shall rule upon any such petitions in its final order in such proceeding within nine months from the date of filing.*

*D. In constructing any such facility contemplated in subsection B, the utility shall develop and submit a plan to the Commission for review that includes the following considerations: (i) options for utilizing local workers; (ii) the economic development benefits of the project for the Commonwealth, including capital investments and job creation; (iii) consultation with the Commonwealth's Chief Workforce Development Officer, the Chief Diversity, Equity, and Inclusion Officer, and the Virginia Economic Development Partnership on opportunities to advance the Commonwealth's workforce and economic development goals, including furtherance of apprenticeship and other workforce training programs; and (iv) giving priority to the hiring, apprenticeship, and training of veterans, as that term is defined in § **2.2-2000.1**, local workers, and workers from historically economically disadvantaged communities.*

E. Any project constructed or purchased pursuant to subsection B shall (i) be subject to competitive procurement or solicitation for a substantial majority of the services and equipment, exclusive of interconnection costs, associated with the facility's construction; (ii) involve at least one experienced developer; and (iii) demonstrate the economic development benefits within the Commonwealth, including capital investments and job creation. A utility may give appropriate consideration to suppliers and developers that have demonstrated successful experience in offshore wind.

F. Any project shall include an environmental and fisheries mitigation plan submitted to the Commission for the construction and operation of such offshore wind facilities, provided that such plan includes an explicit description of the best management practices the bidder will employ that considers the latest science at the time the proposal is made to mitigate adverse impacts to wildlife, natural resources, ecosystems, and traditional or existing water-dependent uses. The plan shall include a summary of pre-construction assessment activities, consistent with federal requirements, to determine the spatial and temporal presence and abundance of marine mammals, sea turtles, birds, and bats in the offshore wind lease area.

*§ **56-585.5**. Generation of electricity from renewable and zero carbon sources.*

A. As used in this section:

"Accelerated renewable energy buyer" means a commercial or industrial customer of a Phase I or Phase II Utility, irrespective of generation supplier, with an aggregate load over 25 megawatts in the prior calendar year, that enters into arrangements pursuant to subsection G, as certified by the Commission.

"Aggregate load" means the combined electrical load associated with selected accounts of an accelerated renewable energy buyer with the same legal entity name as, or in the names of affiliated entities that control, are controlled by, or are under common control of, such legal entity or are the names of affiliated entities under a common parent.

*"Control" has the same meaning as provided in § **56-585.1:11**.*

"Falling water" means hydroelectric resources, including run-of-river generation from a combined pumped-storage and run-of-river facility. "Falling water" does not include electricity generated from pumped-storage facilities.

*"Low-income qualifying projects" means a project that provides a minimum of 50 percent of the respective electric output to low-income utility customers as that term is defined in § **56-576**.*

*"Phase I Utility" has the same meaning as provided in subdivision A 1 of § **56-585.1**.*

*"Phase II Utility" has the same meaning as provided in subdivision A 1 of § **56-585.1**.*

*"Previously developed project site" means any property, including related buffer areas, if any, that has been previously disturbed or developed for non-single-family residential, nonagricultural, or nonsilvicultural use, regardless of whether such property currently is being used for any purpose. "Previously developed project site" includes a brownfield as defined in § **10.1-1230** or any parcel that has been previously used (i) for a retail, commercial, or industrial purpose; (ii) as a parking lot; (iii) as the site of a parking lot canopy or structure; (iv) for mining, which is any lands affected by coal mining that took place before August 3, 1977, or any lands upon which extraction activities have been permitted by the Department of Mines, Minerals and Energy under Title 45.1; (v) for quarrying; or (vi) as a landfill.*

"Total electric energy" means total electric energy sold to retail customers in the Commonwealth service territory of a Phase I or Phase II Utility, other than accelerated renewable energy buyers, by the incumbent electric utility or other retail supplier of electric energy in the previous calendar year, excluding an amount equivalent to the annual percentages of the electric energy that was supplied to such customer from nuclear generating plants located within the Commonwealth in the previous calendar year, provided such nuclear units were operating by July 1, 2020, or from any zero-carbon electric generating facilities not otherwise RPS eligible sources and placed into service in the Commonwealth after July 1, 2030.

"Zero-carbon electricity" means electricity generated by any generating unit that does not emit carbon dioxide as a by-product of combusting fuel to generate electricity.

B. 1. By December 31, 2024, except for any coal-fired electric generating units (i) jointly owned with a cooperative utility or (ii) owned and operated by a Phase II Utility located in the coalfield region of the Commonwealth that co-fires with biomass, any Phase I and Phase II Utility shall retire all generating units principally fueled by oil with a rated capacity in excess of 500 megawatts and all coal-fired electric generating units operating in the Commonwealth.

2. By December 31, 2028, each Phase I and II Utility shall retire all biomass-fired electric generating units that do not co-fire with coal.

3. By December 31, 2045, each Phase I and II Utility shall retire all other electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity.

4. A Phase I or Phase II Utility may petition the Commission for relief from the requirements of this subsection on the basis that the requirement would threaten the reliability or security of electric service to customers. The Commission shall consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition.

*C. Each Phase I and Phase II Utility shall participate in a renewable energy portfolio standard program (RPS Program) that establishes annual goals for the sale of renewable energy to all retail customers in the utility's service territory, other than accelerated renewable energy buyers pursuant to subsection G, regardless of whether such customers purchase electric supply service from the utility or from suppliers other than the utility. To comply with the RPS Program, each Phase I and Phase II Utility shall procure and retire Renewable Energy Certificates (RECs) originating from renewable energy standard eligible sources (RPS eligible sources). For purposes of complying with the RPS Program from 2021 to 2024, a Phase I and Phase II Utility may use RECs from any renewable energy facility, as defined in § **56-576**, provided that such facilities are located in the Commonwealth or are physically located within the PJM Interconnection, LLC (PJM) region. However, at no time during this period or thereafter may any Phase I or Phase II Utility use RECs from (i) renewable thermal energy, (ii) renewable thermal energy equivalent, (iii) biomass-fired facilities that are outside the Commonwealth, or (iv) biomass-fired facilities operating in*

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the Commonwealth as of January 1, 2020, that supply 10 percent or more of their annual net electrical generation to the electric grid or more than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected. From compliance year 2025 and all years after, each Phase I and Phase II Utility may only use RECs from RPS eligible sources for compliance with the RPS Program.

In order to qualify as RPS eligible sources, such sources must be (a) electric-generating resources that generate electric energy derived from solar or wind located in the Commonwealth or off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth or physically located within the PJM region; (b) falling water resources located in the Commonwealth or physically located within the PJM region that were in operation as of January 1, 2020, that are owned by a Phase I or Phase II Utility or for which a Phase I or Phase II Utility has entered into a contract prior to January 1, 2020, to purchase the energy, capacity, and renewable attributes of such falling water resources; (c) non-utility-owned resources from falling water that (1) are less than 65 megawatts, (2) began commercial operation after December 31, 1979, or (3) added incremental generation representing greater than 50 percent of the original nameplate capacity after December 31, 1979, provided that such resources are located in the Commonwealth or are physically located within the PJM region; (d) waste-to-energy or landfill gas-fired generating resources located in the Commonwealth and in operation as of January 1, 2020, provided that such resources do not use waste heat from fossil fuel combustion or forest or woody biomass as fuel; or (e) biomass-fired facilities in operation in the Commonwealth and in operation as of January 1, 2020, that supply no more than 10 percent of their annual net electrical generation to the electric grid or no more than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected. Regardless of any future maintenance, expansion, or refurbishment activities, the total amount of RECs that may be sold by any RPS eligible source using biomass in any year shall be no more than the number of megawatt hours of electricity produced by that facility in 2019; however, in no year may any RPS eligible source using biomass sell RECs in excess of the actual megawatt-hours of electricity generated by such facility that year. In order to comply with the RPS Program, each Phase I and Phase II Utility may use and retire the environmental attributes associated with any existing owned or contracted solar, wind, or falling water electric generating resources in operation, or proposed for operation, in the Commonwealth or physically located within the PJM region, with such resource qualifying as a Commonwealth-located resource for purposes of this subsection, as of January 1, 2020, provided such renewable attributes are verified as RECs consistent with the PJM-EIS Generation Attribute Tracking System.

The RPS Program requirements shall be a percentage of the total electric energy sold in the previous calendar year and shall be implemented in accordance with the following schedule:

Phase I Utilities		*Phase II Utilities*	
Year	*RPS Program Requirement*	*Year*	*RPS Program Requirement*
2021	*6%*	*2021*	*14%*
2022	*7%*	*2022*	*17%*
2023	*8%*	*2023*	*20%*
2024	*10%*	*2024*	*23%*
2025	*14%*	*2025*	*26%*

2026	*17%*	*2026*	*29%*
2027	*20%*	*2027*	*32%*
2028	*24%*	*2028*	*35%*
2029	*27%*	*2029*	*38%*
2030	*30%*	*2030*	*41%*
2031	*33%*	*2031*	*45%*
2032	*36%*	*2032*	*49%*
2033	*39%*	*2033*	*52%*
2034	*42%*	*2034*	*55%*
2035	*45%*	*2035*	*59%*
2036	*53%*	*2036*	*63%*
2037	*53%*	*2037*	*67%*
2038	*57%*	*2038*	*71%*
2039	*61%*	*2039*	*75%*
2040	*65%*	*2040*	*79%*
2041	*68%*	*2041*	*83%*
2042	*71%*	*2042*	*87%*
2043	*74%*	*2043*	*91%*
2044	*77%*	*2044*	*95%*
2045	*80%*	*2045 and thereafter*	*100%*

2046[I/A]	*84%*
2047	*88%*
2048	*92%*
2049	*96%*
2050 and thereafter	*100%*

A Phase II Utility shall meet one percent of the RPS Program requirements in any given compliance year with solar, wind, or anaerobic digestion resources of one megawatt or less located in the Commonwealth, with not more than 3,000 kilowatts at any single location or at contiguous locations owned by the same entity or affiliated entities and, to the extent that low-income qualifying projects are available, then no less than 25 percent of such one percent shall be composed of low-income qualifying projects.

Beginning with the 2025 compliance year and thereafter, at least 75 percent of all RECs used by a Phase II Utility in a compliance period shall come from RPS eligible resources located in the Commonwealth.

*Any Phase I or Phase II Utility may apply renewable energy sales achieved or RECs acquired in excess of the sales requirement for that RPS Program to the sales requirements for RPS Program requirements in the year in which it was generated and the five calendar years after the renewable energy was generated or the RECs were created. To the extent that a Phase I or Phase II Utility procures RECs for RPS Program compliance from resources the utility does not own, the utility shall be entitled to recover the costs of such certificates at its election pursuant to § **56-249.6** or subdivision A 5 d of § **56-585.1**.*

*D. Each Phase I or Phase II Utility shall petition the Commission for necessary approvals to procure zero-carbon electricity generating capacity as set forth in this subsection and energy storage resources as set forth in subsection E. To the extent that a Phase I or Phase II Utility constructs or acquires new zero-carbon generating facilities or energy storage resources, the utility shall petition the Commission for the recovery of the costs of such facilities, at the utility's election, either through its rates for generation and distribution services or through a rate adjustment clause pursuant to subdivision A 6 of § **56-585.1**. All costs not sought for recovery through a rate adjustment clause pursuant to subdivision A 6 of § **56-585.1** associated with generating facilities provided by sunlight or onshore or offshore wind are also eligible to be applied by the utility as a customer credit reinvestment offset as provided in subdivision A 8 of § **56-585.1**. Costs associated with the purchase of energy, capacity, or environmental attributes from facilities owned by the persons other than the utility required by this subsection shall be recovered by the utility either through its rates for generation and distribution services or pursuant to § **56-249.6**.*

1. Each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of 600 megawatts of generating capacity using energy derived from sunlight or onshore wind.

a. By December 31, 2023, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

b. By December 31, 2027, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or

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onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

c. By December 31, 2030, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

*d. Nothing in this subdivision 1 shall prohibit such Phase I Utility from constructing, acquiring, or entering into agreements to purchase the energy, capacity, and environmental attributes of more than 600 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to §§ **56-580** and **56-585.1**.*

*2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to (i) construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, which shall include 1,100 megawatts of solar generation of a nameplate capacity not to exceed three megawatts per individual project and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar facilities owned by persons other than a utility, including utility affiliates and deregulated affiliates and (ii) pursuant to § **56-585.1:11**, construct or purchase one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth with an aggregate capacity of up to 5,200 megawatts. At least 200 megawatts of the 16,100 megawatts shall be placed on previously developed project sites.*

a. By December 31, 2024, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

b. By December 31, 2027, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

c. By December 31, 2030, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 4,000 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

d. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 6,100 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

e. Nothing in this subdivision 2 shall prohibit such Phase II Utility from constructing, acquiring, or entering into agreements to purchase the energy, capacity, and environmental attributes of more than 16,100 megawatts of generating capacity located in

*the Commonwealth using energy derived from sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to §§ **56-580** and **56-585.1**.*

*3. Nothing in this section shall prohibit a utility from petitioning the Commission to construct or acquire zero-carbon electricity or from entering into contracts to procure the energy, capacity, and environmental attributes of zero-carbon electricity generating resources in excess of the requirements in subsection B. The Commission shall determine whether to approve such petitions on a stand-alone basis pursuant to §§ **56-580** and **56-585.1**, provided that the Commission's review shall also consider whether the proposed generating capacity (i) is necessary to meet the utility's native load, (ii) is likely to lower customer fuel costs, (iii) will provide economic development opportunities in the Commonwealth, and (iv) serves a need that cannot be more affordably met with demand-side or energy storage resources.*

Each Phase I and Phase II Utility shall, at least once every year, conduct a request for proposals for new solar and wind resources. Such requests shall quantify and describe the utility's need for energy, capacity, or renewable energy certificates. The requests for proposals shall be publicly announced and made available for public review on the utility's website at least 45 days prior to the closing of such request for proposals. The requests for proposals shall provide, at a minimum, the following information: (a) the size, type, and timing of resources for which the utility anticipates contracting; (b) any minimum thresholds that must be met by respondents; (c) major assumptions to be used by the utility in the bid evaluation process, including environmental emission standards; (d) detailed instructions for preparing bids so that bids can be evaluated on a consistent basis; (e) the preferred general location of additional capacity; and (f) specific information concerning the factors involved in determining the price and non-price criteria used for selecting winning bids. A utility may evaluate responses to requests for proposals based on any criteria that it deems reasonable but shall at a minimum consider the following in its selection process: (1) the status of a particular project's development; (2) the age of existing generation facilities; (3) the demonstrated financial viability of a project and the developer; (4) a developer's prior experience in the field; (5) the location and effect on the transmission grid of a generation facility; (6) benefits to the Commonwealth that are associated with particular projects, including regional economic development and the use of goods and services from Virginia businesses; and (7) the environmental impacts of particular resources, including impacts on air quality within the Commonwealth and the carbon intensity of the utility's generation portfolio.

*4. In connection with the requirements of this subsection, each Phase I and Phase II Utility shall, commencing in 2020 and concluding in 2035, submit annually a plan and petition for approval for the development of new solar and onshore wind generation capacity. Such plan shall reflect, in the aggregate and over its duration, the requirements of subsection D concerning the allocation percentages for construction or purchase of such capacity. Such petition shall contain any request for approval to construct such facilities pursuant to subsection D of § **56-580** and a request for approval or update of a rate adjustment clause pursuant to subdivision A 6 of § **56-585.1** to recover the costs of such facilities. Such plan shall also include the utility's plan to meet the energy storage project targets of subsection E, including the goal of installing at least 10 percent of such energy storage projects behind the meter. In determining whether to approve the utility's plan and any associated petition requests, the Commission shall determine whether they are reasonable and prudent and shall give due consideration to (i) the RPS and carbon dioxide reduction requirements in this section, (ii) the promotion of new renewable generation and energy storage resources within the Commonwealth, and associated economic development, and (iii) fuel savings projected to be achieved by the plan. Notwithstanding any other provision of this title, the Commission's final order regarding any such petition and associated requests shall be entered by the Commission not more than six months after the date of the filing of such petition.*

*5. If, in any year, a Phase I or Phase II Utility is unable to meet the compliance obligation of the RPS Program requirements or if the cost of RECs necessary to comply with RPS Program requirements exceeds $45 per megawatt hour, such supplier shall be obligated to make a deficiency payment equal to $45 for each megawatt-hour shortfall for the year of noncompliance, except that the deficiency payment for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in the Commonwealth shall be $75 per megawatts hour for resources one megawatt and lower. The amount of any deficiency payment shall increase by one percent annually after 2021. A Phase I or Phase II Utility shall be entitled to recover the costs of such payments as a cost of compliance with the requirements of this subsection pursuant to subdivision A 5 d of § **56-585.1**. All proceeds from the deficiency payments shall be deposited into an interest-bearing account administered by the Department of Mines, Minerals and Energy. In administering this account, the Department of Mines, Minerals and Energy shall manage the account as follows: (i) 50 percent of total revenue shall be directed to job training programs in historically economically disadvantaged communities; (ii) 16 percent of total revenue shall be directed to energy efficiency measures for public facilities;*

(iii) 30 percent of total revenue shall be directed to renewable energy programs located in historically economically disadvantaged communities; and (iv) four percent of total revenue shall be directed to administrative costs.

E. To enhance reliability and performance of the utility's generation and distribution system, each Phase I and Phase II Utility shall petition the Commission for necessary approvals to construct or acquire new, utility-owned energy storage resources.

*1. By December 31, 2035, each Phase I Utility shall petition the Commission for necessary approvals to construct or acquire 400 megawatts of energy storage capacity. Nothing in this subdivision shall prohibit a Phase I Utility from constructing or acquiring more than 400 megawatts of energy storage, provided that the utility receives approval from the Commission pursuant to §§ **56-580** and **56-585.1**.*

*2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to construct or acquire 2,700 megawatts of energy storage capacity. Nothing in this subdivision shall prohibit a Phase II Utility from constructing or acquiring more than 2,700 megawatts of energy storage, provided that the utility receives approval from the Commission pursuant to §§ **56-580** and **56-585.1**.*

3. No single energy storage project shall exceed 500 megawatts in size, except that a Phase II Utility may procure a single energy storage project up to 800 megawatts.

4. All energy storage projects procured pursuant to this subsection shall meet the competitive procurement protocols established in subdivision D 3.

5. After July 1, 2020, at least 35 percent of the energy storage facilities placed into service shall be (i) purchased by the public utility from a party other than the public utility or (ii) owned by a party other than a public utility, with the capacity from such facilities sold to the public utility. By January 1, 2021, the Commission shall adopt regulations to achieve the deployment of energy storage for the Commonwealth required in subdivisions 1 and 2, including regulations that set interim targets and update existing utility planning and procurement rules. The regulations shall include programs and mechanisms to deploy energy storage, including competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs.

*F. All costs incurred by a Phase I or Phase II Utility related to compliance with the requirements of this section or pursuant to § **56-585.1:11**, including (i) costs of generation facilities powered by sunlight or onshore or offshore wind, or energy storage facilities, that are constructed or acquired by a Phase I or Phase II Utility after July 1, 2020, (ii) costs of capacity, energy, or environmental attributes from generation facilities powered by sunlight or onshore or offshore wind, or falling water, or energy storage facilities purchased by the utility from persons other than the utility through agreements after July 1, 2020, and (iii) all other costs of compliance, including costs associated with the purchase of RECs associated with RPS Program requirements pursuant to this section shall be recovered from all retail customers in the service territory of a Phase I or Phase II Utility as a non-bypassable charge, irrespective of the generation supplier of such customer, except (a) as provided in subsection G for an accelerated renewable energy buyer or (b) as provided in subdivision C 3 of § **56-585.1:11**, with respect to the costs of an offshore wind generation facility, for a PIPP eligible utility customer or an advanced clean energy buyer or qualifying large general service customer, as those terms are defined in § **56-585.11**. If a Phase I or Phase II Utility serves customers in more than one jurisdiction, such utility shall recover all of the costs of compliance with the RPS Program requirements from its Virginia customers through the applicable cost recovery mechanism, and all associated energy, capacity, and environmental attributes shall be assigned to Virginia to the extent that such costs are requested but not recovered from any system customers outside the Commonwealth.*

By September 1, 2020, the Commission shall direct the initiation of a proceeding for each Phase I and Phase II Utility to review and determine the amount of such costs, net of benefits, that should be allocated to retail customers within the utility's service territory which have elected to receive electric supply service from a supplier of electric energy other than the utility, and shall direct that tariff provisions be implemented to recover those costs from such customers beginning no later than January 1, 2021. Thereafter, such charges and tariff provisions shall be updated and trued up by the utility on an annual basis, subject to continuing review and approval by the Commission.

G. 1. An accelerated renewable energy buyer may contract with a Phase I or Phase II Utility, or a person other than a Phase I or Phase II Utility, to obtain (i) RECs from RPS eligible resources or (ii) bundled capacity, energy, and RECs from solar or wind generation resources located within the PJM region and initially placed in commercial operation after January 1, 2015.

*Such an accelerated renewable energy buyer may offset all or a portion of its electric load for purposes of RPS compliance through such arrangements. An accelerated renewable energy buyer shall be exempt from the assignment of non-bypassable RPS compliance costs pursuant to subsection F, with the exception of the costs of an offshore wind generating facility pursuant to § **56-585.1:11**, based on the amount of RECs obtained pursuant to this subsection in proportion to the customer's total electric energy consumption, on an annual basis, however, an accelerated renewable energy buyer obtaining RECs only shall not be exempt from costs related to procurement of new solar or onshore wind generation capacity, energy, or environmental attributes, or energy storage facilities by the utility pursuant to subsections D and E. To the extent that an accelerated renewable energy buyer contracts for the capacity of new solar or wind generation resources pursuant to this subsection, the aggregate amount of such nameplate capacity shall be offset from the utility's procurement requirements pursuant to subsection D. All RECs associated with contracts entered into by an accelerated renewable energy buyer with the utility, or a person other than the utility, for an RPS Program shall not be credited to the utility's compliance with its RPS requirements, and the calculation of the utility's RPS Program requirements shall not include the electric load covered by customers certified as accelerated renewable energy buyers.*

2. Each Phase I or Phase II Utility shall certify, and verify as necessary, to the Commission that the accelerated renewable energy buyer has satisfied the exemption requirements of this subsection for each year, or an accelerated renewable energy buyer may choose to certify satisfaction of this exemption by reporting to the Commission individually. The Commission may promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

*3. Provided that no incremental costs associated with any contract between a Phase I or Phase II Utility and an accelerated renewable energy buyer is allocated to or recovered from any other customer of the utility, any such contract with an accelerated renewable energy buyer that is a jurisdictional customer of the utility shall not be deemed a special rate or contract requiring Commission approval pursuant to § **56-235.2**.*

*H. No customer of a Phase II Utility with a peak demand in excess of 100 megawatts in 2019 that elected pursuant to subdivision A 3 of § **56-577** to purchase electric energy from a competitive service provider prior to April 1, 2019, shall be allocated any non-bypassable charges pursuant to subsection F for such period that the customer is not purchasing electric energy from the utility, and such customer's electric load shall not be included in the utility's RPS Program requirements. No customer of a Phase I Utility that elected pursuant to subdivision A 3 of § **56-577** to purchase electric energy from a competitive service provider prior to February 1, 2019, shall be allocated any non-bypassable charges pursuant to subsection F for such period that the customer is not purchasing electric energy from the utility, and such customer's electric load shall not be included in the utility's RPS Program requirements.*

*I. Nothing in this section shall apply to any entity organized under Chapter 9.1 (§ 5**6-231.15** et seq.).*

J. The Commission shall adopt such rules and regulations as may be necessary to implement the provisions of this section, including a requirement that participants verify whether the RPS Program requirements are met in accordance with this section.

*§ **56-585.6**. Universal service fee; Percentage of Income Payment Program.*

A. The Commission shall, after notice and opportunity for hearing, initiate a proceeding to establish the rates, terms, and conditions of a non-bypassable universal service fee to fund the Percentage of Income Payment Program (PIPP). Such universal service fee shall be allocated to retail electric customers of a Phase I and Phase II Utility on the basis of the amount of kilowatt-hours used and be established at such level to adequately address the PIPP's objectives to (i) reduce the energy burden of eligible participants by limiting electric bill payments directly to no more than six percent of the eligible participant's annual household income if the household's heating source is anything other than electricity, and to no more than 10 percent of an eligible participant's annual household income on electricity costs if the household's heating source is electricity, and (ii) reduce the amount of electricity used by the eligible participant's household through participation in weatherization or energy efficiency programs and energy conservation education programs.

B. The Commission shall determine the reasonable administrative costs for the investor-owned utility to collect the universal service fee and remit such funds to the Percentage of Income Payment Fund, and any other administrative costs the investor-owned utility may incur in complying with the PIPP, and shall determine the proper recovery mechanism for such costs. A Phase I and Phase II Utility shall not be eligible to earn a rate of return on any equity or costs incurred to comply with the program requirements or implementation.

§ 56-594. Net energy metering provisions.

A. The Commission shall establish by regulation a program that affords eligible customer-generators the opportunity to participate in net energy metering, and a program, to begin no later than July 1, 2014, for customers of investor-owned utilities and to begin no later than July 1, 2015, and to end July 1, 2019, for customers of electric cooperatives as provided in subsection G, to afford eligible agricultural customer-generators the opportunity to participate in net energy metering. The regulations may include, but need not be limited to, requirements for (i) retail sellers; (ii) owners or operators of distribution or transmission facilities; (iii) providers of default service; (iv) eligible customer-generators; (v) eligible agricultural customer-generators; or (vi) any combination of the foregoing, as the Commission determines will facilitate the provision of net energy metering, provided that the Commission determines that such requirements do not adversely affect the public interest. On and after July 1, 2017, small agricultural generators or eligible agricultural customer-generators may elect to interconnect pursuant to the provisions of this section or as small agricultural generators pursuant to § 56-594.2, but not both. Existing eligible agricultural customer-generators may elect to become small agricultural generators, but may not revert to being eligible agricultural customer-generators after such election. On and after July 1, 2019, interconnection of eligible agricultural customer-generators shall cease for electric cooperatives only, and such facilities shall interconnect solely as small agricultural generators. For electric cooperatives, eligible agricultural customer-generators whose renewable energy generating facilities were interconnected before July 1, 2019, may continue to participate in net energy metering pursuant to this section for a period not to exceed 25 years from the date of their renewable energy generating facility's original interconnection.

B. For the purpose of this section:

"Eligible agricultural customer-generator" means a customer that operates a renewable energy generating facility as part of an agricultural business, which generating facility (i) uses as its sole energy source solar power, wind power, or aerobic or anaerobic digester gas, (ii) does not have an aggregate generation capacity of more than 500 kilowatts, (iii) is located on land owned or controlled by the agricultural business, (iv) is connected to the customer's wiring on the customer's side of its interconnection with the distributor; (v) is interconnected and operated in parallel with an electric company's transmission and distribution facilities, and (vi) is used primarily to provide energy to metered accounts of the agricultural business. An eligible agricultural customer-generator may be served by multiple meters that are located at separate but contiguous sites, such that the eligible agricultural customer-generator may aggregate in a single account the electricity consumption and generation measured by the meters, provided that the same utility serves all such meters. The aggregated load shall be served under the appropriate tariff.

"Eligible customer-generator" means a customer that owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility that (i) has a capacity of not more than ~~20~~ *25* kilowatts for residential customers and not more than ~~one megawatt~~ *three megawatts* for nonresidential customers on an electrical generating facility placed in service after July 1, 2015; (ii) uses as its total source of fuel renewable energy, as defined in § 56-576; (iii) is located on the customer's premises and is connected to the customer's wiring on the customer's side of its interconnection with the distributor; (iv) is interconnected and operated in parallel with an electric company's transmission and distribution facilities; and (v) is intended primarily to offset all or part of the customer's own electricity requirements. In addition to the electrical generating facility size limitations in clause (i), the capacity of any generating facility installed under this section after July 1, 2015, shall not exceed the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available. *In addition to the electrical generating facility size limitation in clause (i), in the certificated service territory of a Phase I Utility, the capacity of any generating facility installed under this section after July 1, 2020, shall not exceed 100 percent of the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available, and in the certificated service territory of a Phase II Utility, the capacity of any generating facility installed under this section after July 1, 2020, shall not exceed 150 percent of the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available.*

"Net energy metering" means measuring the difference, over the net metering period, between (i) electricity supplied to an eligible customer-generator or eligible agricultural customer-generator from the electric grid and (ii) the electricity generated and fed back to the electric grid by the eligible customer-generator or eligible agricultural customer-generator.

"Net metering period" means the 12-month period following the date of final interconnection of the eligible customer-generator's or eligible agricultural customer-generator's system with an electric service provider, and each 12-month period

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thereafter.

"Small agricultural generator" has the same meaning that is ascribed to that term in § **56-594.2**.

C. The Commission's regulations shall ensure that (i) the metering equipment installed for net metering shall be capable of measuring the flow of electricity in two directions and (ii) any eligible customer-generator seeking to participate in net energy metering shall notify its supplier and receive approval to interconnect prior to installation of an electrical generating facility. The electric distribution company shall have 30 days from the date of notification for residential facilities, and 60 days from the date of notification for nonresidential facilities, to determine whether the interconnection requirements have been met. Such regulations shall allocate fairly the cost of such equipment and any necessary interconnection. An eligible customer-generator's electrical generating system, and each electrical generating system of an eligible agricultural customer-generator, shall meet all applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories. Beyond the requirements set forth in this section and to ensure public safety, power quality, and reliability of the supplier's electric distribution system, an eligible customer-generator or eligible agricultural customer-generator whose electrical generating system meets those standards and rules shall bear all reasonable costs of equipment required for the interconnection to the supplier's electric distribution system, including costs, if any, to (a) install additional controls, (b) perform or pay for additional tests, and (c) purchase additional liability insurance.

D. The Commission shall establish minimum requirements for contracts to be entered into by the parties to net metering arrangements. Such requirements shall protect the eligible customer-generator or eligible agricultural customer-generator against discrimination by virtue of its status as an eligible customer-generator or eligible agricultural customer-generator, and permit customers that are served on time-of-use tariffs that have electricity supply demand charges contained within the electricity supply portion of the time-of-use tariffs to participate as an eligible customer-generator or eligible agricultural customer-generator. Notwithstanding the cost allocation provisions of subsection C, eligible customer-generators or eligible agricultural customer-generators served on demand charge-based time-of-use tariffs shall bear the incremental metering costs required to net meter such customers.

E. If electricity generated by an eligible customer-generator or eligible agricultural customer-generator over the net metering period exceeds the electricity consumed by the eligible customer-generator or eligible agricultural customer-generator, the customer-generator or eligible agricultural customer-generator shall be compensated for the excess electricity if the entity contracting to receive such electric energy and the eligible customer-generator or eligible agricultural customer-generator enter into a power purchase agreement for such excess electricity. Upon the written request of the eligible customer-generator or eligible agricultural customer-generator, the supplier that serves the eligible customer-generator or eligible agricultural customer-generator shall enter into a power purchase agreement with the requesting eligible customer-generator or eligible agricultural customer-generator that is consistent with the minimum requirements for contracts established by the Commission pursuant to subsection D. The power purchase agreement shall obligate the supplier to purchase such excess electricity at the rate that is provided for such purchases in a net metering standard contract or tariff approved by the Commission, unless the parties agree to a higher rate. The eligible customer-generator or eligible agricultural customer-generator owns any renewable energy certificates associated with its electrical generating facility; however, at the time that the eligible customer-generator or eligible agricultural customer-generator enters into a power purchase agreement with its supplier, the eligible customer-generator or eligible agricultural customer-generator shall have a one-time option to sell the renewable energy certificates associated with such electrical generating facility to its supplier and be compensated at an amount that is established by the Commission to reflect the value of such renewable energy certificates. Nothing in this section shall prevent the eligible customer-generator or eligible agricultural customer-generator and the supplier from voluntarily entering into an agreement for the sale and purchase of excess electricity or renewable energy certificates at mutually-agreed upon prices if the eligible customer-generator or eligible agricultural customer-generator does not exercise its option to sell its renewable energy certificates to its supplier at Commission-approved prices at the time that the eligible customer-generator or eligible agricultural customer-generator enters into a power purchase agreement with its supplier. All costs incurred by the supplier to purchase excess electricity and renewable energy certificates from eligible customer-generators or eligible agricultural customer-generators shall be recoverable through its Renewable Energy Portfolio Standard (RPS) rate adjustment clause, if the supplier has a Commission-approved RPS plan. If not, then all costs shall be recoverable through the supplier's fuel adjustment clause. For purposes of this section, "all costs" shall be defined as the rates paid to the eligible customer-generator or eligible agricultural customer-generator for the purchase of excess electricity and renewable energy certificates and any administrative costs incurred to manage the eligible customer-generator's or eligible agricultural customer-generator's power purchase

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arrangements. The net metering standard contract or tariff shall be available to eligible customer-generators or eligible agricultural customer-generators on a first-come, first-served basis in each electric distribution company's Virginia service area until the rated generating capacity owned and operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators in the Commonwealth reaches ~~one~~ *six* percent*, in the aggregate, five percent of which is available to all customers and one percent of which is available only to low-income utility customers* of each electric distribution company's adjusted Virginia peak-load forecast for the previous year ~~(the systemwide cap)~~, and shall require the supplier to pay the eligible customer-generator or eligible agricultural customer-generator for such excess electricity in a timely manner at a rate to be established by the Commission.

On and after the earlier of (i) 2024 for a Phase I Utility or 2025 for a Phase II Utility or (ii) when the aggregate rated generating capacity owned and operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators in the Commonwealth reaches three percent of a Phase I or Phase II Utility's adjusted Virginia peak-load forecast for the previous year, the Commission shall conduct a net energy metering proceeding.

In any net energy metering proceeding, the Commission shall, after notice and opportunity for hearing, evaluate and establish (a) an amount customers shall pay on their utility bills each month for the costs of using the utility's infrastructure; (b) an amount the utility shall pay to appropriately compensate the customer, as determined by the Commission, for the total benefits such facilities provide; (c) the direct and indirect economic impact of net metering to the Commonwealth; and (d) any other information the Commission deems relevant. The Commission shall establish an appropriate rate structure related thereto, which shall govern compensation related to all eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators, except low-income utility customers, that interconnect after the effective date established in the Commission's final order. Nothing in the Commission's final order shall affect any eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators who interconnect before the effective date of such final order. As part of the net energy metering proceeding, the Commission shall evaluate the six percent aggregate net metering cap and may, if appropriate, raise or remove such cap. The Commission shall enter its final order in such a proceeding no later than 12 months after it commences such proceeding, and such final order shall establish a date by which the new terms and conditions shall apply for interconnection and shall also provide that, if the terms and conditions of compensation in the final order differ from the terms and conditions available to customers before the proceeding, low-income utility customers may interconnect under whichever terms are most favorable to them.

F. Any residential eligible customer-generator or eligible agricultural customer-generator who owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility with a capacity that exceeds ~~10~~ *15* kilowatts shall pay to its supplier, in addition to any other charges authorized by law, a monthly standby charge. The amount of the standby charge and the terms and conditions under which it is assessed shall be in accordance with a methodology developed by the supplier and approved by the Commission. The Commission shall approve a supplier's proposed standby charge methodology if it finds that the standby charges collected from all such eligible customer-generators and eligible agricultural customer-generators allow the supplier to recover only the portion of the supplier's infrastructure costs that are properly associated with serving such eligible customer-generators or eligible agricultural customer-generators. Such an eligible customer-generator or eligible agricultural customer-generator shall not be liable for a standby charge until the date specified in an order of the Commission approving its supplier's methodology.

G. On and after the later of July 1, 2019, or the effective date of regulations that the Commission is required to adopt pursuant to § **56-594.01**, (i) net energy metering in the service territory of each electric cooperative shall be conducted as provided in a program implemented pursuant to § **56-594.01** and (ii) the provisions of this section shall not apply to net energy metering in the service territory of an electric cooperative except as provided in § **56-594.01**.

H. The Commission may adopt such rules or establish such guidelines as may be necessary for its general administration of this section.

I. When the Commission conducts a net energy metering proceeding, it shall:

1. Investigate and determine the costs and benefits of the current net energy metering program;

2. Establish an appropriate netting measurement interval for a successor tariff that is just and reasonable in light of the costs and benefits of the net metering program in aggregate, and applicable to new requests for net energy metering service; and

3. Determine a specific avoided cost for customer-generators, the different type of customer-generator technologies where the Commission deems it appropriate, and establish the methodology for determining the compensation rate for any net excess generation determined according to the applicable net measurement interval for any new tariff.

J. In evaluating the costs and benefits of the net energy metering program, the Commission shall consider:

1. The aggregate impact of customer-generators on the electric utility's long-run marginal costs of generation, distribution, and transmission;

2. The cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study;

3. The direct and indirect economic impact of the net energy metering program to the Commonwealth; and

4. Any other information it deems relevant, including environmental and resilience benefits of customer-generator facilities.

§ **56-596.2**. Energy efficiency programs; financial assistance for low-income customers.

~~Each Phase I Utility and Phase II Utility, as such terms are defined in subdivision A 1 of § 56-585.1,~~ *A. Notwithstanding subsection G of § 56-580, or any other provision of law, each incumbent investor-owned electric utility* shall develop ~~a~~ proposed ~~program of~~ energy ~~conservation measures~~ *efficiency programs*. Any program shall provide for the submission of a petition or petitions for approval to design, implement, and operate energy efficiency programs pursuant to subdivision A 5 c of § **56-585.1**. At least ~~five~~ *15* percent of such *proposed costs of* energy efficiency programs shall *be allocated to programs designed to* benefit low-income, elderly, ~~and~~ *or* disabled individuals *or veterans*.

B. Notwithstanding any other provision of law, each investor-owned incumbent electric utility shall implement energy efficiency programs and measures to achieve the following total annual energy savings:

1. For Phase I electric utilities:

a. In calendar year 2022, at least 0.5 percent of the average annual energy jurisdictional retail sales by that utility in 2019;

b. In calendar year 2023, at least 1.0 percent of the average annual energy jurisdictional retail sales by that utility in 2019;

c. In calendar year 2024, at least 1.5 percent of the average annual energy jurisdictional retail sales by that utility in 2019; and

d. In calendar year 2025, at least 2.0 percent of the average annual energy jurisdictional retail sales by that utility in 2019;

2. For Phase II electric utilities:

a. In calendar year 2022, at least 1.25 percent of the average annual energy jurisdictional retail sales by that utility in 2019;

b. In calendar year 2023, at least 2.5 percent of the average annual energy jurisdictional retail sales by that utility in 2019;

c. In calendar year 2024, at least 3.75 percent of the average annual energy jurisdictional retail sales by that utility in 2019; and

d. In calendar year 2025, at least 5.0 percent of the average annual energy jurisdictional retail sales by that utility in 2019; and

3. For the time period 2026 through 2028, and for every successive three-year period thereafter, the Commission shall establish new energy efficiency savings targets. In advance of the effective date of such targets, the Commission shall, after notice and opportunity for hearing, initiate proceedings to establish such targets. As part of such proceeding, the Commission shall consider the feasibility of achieving energy efficiency goals and future energy efficiency savings through cost-effective programs and measures. The Commission shall annually review the feasibility of the energy efficiency program savings in this section and report to the Chairs of the House Committee on Labor and Commerce and the Senate Committee on Commerce and Labor and the Secretary of Natural Resources and the Secretary of Commerce and Trade on such feasibility by October 1, 2022, and each year thereafter.

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C. The projected costs for the utility to design, implement, and operate such energy efficiency programs~~, including a margin to be recovered on operating expenses,~~ shall be no less than an aggregate amount of $140 million for a Phase I Utility and $870 million for a Phase II Utility for the period beginning July 1, 2018, and ending July 1, 2028, including any existing approved energy efficiency programs. In developing such portfolio of energy efficiency programs, each utility shall utilize a stakeholder process, to be facilitated by an independent monitor compensated under the funding provided pursuant to subdivision E of § **56-592.1**, to provide input and feedback on *(i)* the development of such energy efficiency programs *and portfolios of programs; (ii) compliance with the total annual energy savings set forth in this subsection and how such savings affect utility integrated resource plans; (iii) recommended policy reforms by which the General Assembly or the Commission can ensure maximum and cost-effective deployment of energy efficiency technology across the Commonwealth; and (iv) best practices for evaluation, measurement, and verification for the purposes of assessing compliance with the total annual energy savings set forth in subsection B. Utilities shall utilize the services of a third party to perform evaluation, measurement, and verification services to determine a utility's total annual savings as required by this subsection, as well as the annual and lifecycle net and gross energy and capacity savings, related emissions reductions, and other quantifiable benefits of each program; total customer bill savings that the programs and portfolios produce; and utility spending on each program, including any associated administrative costs. The third-party evaluator shall include and review each utility's avoided costs and cost-benefit analyses. The findings and reports of such third parties shall be concurrently provided to both the Commission and the utility, and the Commission shall make each such final annual report easily and publicly accessible online.* Such stakeholder process shall include *the participation of* representatives from each utility, *relevant directors, deputy directors, and staff members of* the~~ State Corporation~~ Commission *who participate in approval and oversight of utility efficiency programs*, the office of Consumer Counsel of the Attorney General, the Department of Mines, Minerals and Energy, energy efficiency program implementers, energy efficiency providers, residential and small business customers, and any other interested stakeholder who the independent monitor deems appropriate for inclusion in such process. The independent monitor shall convene meetings of the participants in the stakeholder process not less frequently than twice in each calendar year during the period beginning July 1, 2019, and ending July 1, 2028. The independent monitor shall report on the status of the energy efficiency stakeholder process, including ~~(i)~~ *(a)* the objectives established by the stakeholder group during this process related to programs to be proposed,~~ (ii)~~ *(b)* recommendations related to programs to be proposed that result from the stakeholder process, and~~ (iii)~~ *(c)* the status of those recommendations, in addition to the petitions filed and the determination thereon, to the Governor, the State Corporation Commission, and the Chairmen of the House *Committee on Labor and Commerce* and Senate *Committee on* Commerce and Labor~~ Committees~~ on July 1, 2019, and annually thereafter through July 1, 2028.

*D. Nothing in this section shall apply to any entity organized under Chapter 9.1 (§ **56-231.15** et seq.).*

2. That § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, is amended and reenacted as follows:

§ 1. That the State Corporation Commission (Commission) shall conduct pilot programs under which a person that owns or operates a solar-powered or wind-powered electricity generation facility located on premises owned or leased by an eligible customer-generator, as defined in § **56-594** of the Code of Virginia, shall be permitted to sell the electricity generated from such facility exclusively to such eligible customer-generator under a power purchase agreement used to provide third party financing of the costs of such a renewable generation facility (third party power purchase agreement), subject to the following terms, conditions, and restrictions:

a.~~ A~~ *Notwithstanding subsection G of § **56-580** of the Code of Virginia or any other provision of law, a* pilot program shall be conducted within the certificated service territory of each investor-owned electric utility~~ other than a utility described in subsection G of § 56-580 of the Code of Virginia~~ ("Pilot Utility")~~, provided that within the certificated service territory of an investor-owned utility that was not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, nonprofit, private institutions of higher education as defined in § 23.1-100 of the Code of Virginia that are not being served by generation provided under subdivision A 5 of § 56-577 of the Code of Virginia shall be deemed to be customer-generators eligible to participate in the pilot program~~;

b. The aggregated capacity of all generation facilities that are subject to such third party power purchase agreements at any time during the pilot program shall not exceed~~ 50~~ *500* megawatts *for Virginia jurisdictional customers and 500 megawatts for Virginia nonjurisdictional customers* for an investor-owned utility that was bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, or~~ seven~~ *40* megawatts for an investor-owned utility that was not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002.

Such limitation on the aggregated capacity of such facilities shall constitute a portion of the existing limit of ~~one~~ *six* percent of each Pilot Utility's adjusted Virginia peak-load forecast for the previous year that is available to eligible customer-generators pursuant to subsection E of § **56-594** of the Code of Virginia. Notwithstanding any provision of this act that incorporates provisions of § **56-594**, the seller and the customer shall elect either to (i) enter into their third party power purchase agreement subject to the conditions and provisions of the Pilot Utility's net energy metering program under § **56-594** or (ii) provide that electricity generated from the generation facilities subject to the third party power purchase agreement will not be net metered under § **56-594**, provided that an election not to net meter under § **56-594** shall not exempt the third party power purchase agreement and the parties thereto from the requirements of this act that incorporate provisions of § **56-594**;

c. A solar-powered or wind-powered generation facility with a capacity of no less than 50 kilowatts and no more than ~~one megawatt~~ *three megawatts* shall be eligible for a third party power purchase agreement under ~~the~~ *a* pilot program; however, if the customer under such agreement is *a low-income utility customer, as defined in § **56-576** of the Code of Virginia, or is* an entity with tax-exempt status in accordance with § 501(c) of the Internal Revenue Code of 1954, as amended, then such facility is eligible for the pilot program even if it does not meet the 50 kilowatts minimum size requirement. The maximum generation capacity of ~~one megawatt~~ *three megawatts* shall not affect the limits on the capacity of electrical generating capacities of ~~20~~ *25* kilowatts for residential customers and ~~500 kilowatts~~ *three megawatts* for nonresidential customers set forth in subsection B of § **56-594** of the Code of Virginia, which limitations shall continue to apply to net energy metering generation facilities regardless of whether they are the subject of a third party power purchase agreement under the pilot program;

d. A generation facility that is the subject of a third party power purchase agreement under the pilot program shall serve only one customer, and a third party power purchase agreement shall not serve multiple customers;

e. The customer under a third party power purchase agreement under the pilot program shall be subject to the interconnection and other requirements imposed on eligible customer-generators pursuant to subsection C of § **56-594** of the Code of Virginia, including the requirement that the customer bear the reasonable costs, as determined by the Commission, of the items described in clauses (i), (ii), and (iii) of such subsection;

f. A third party power purchase agreement under the pilot program shall not be valid unless it conforms in all respects to the requirements of the pilot program conducted under the provisions of this act and unless the Commission and the Pilot Utility are provided written notice of the parties' intent to enter into a third party power purchase agreement not less than 30 days prior to the agreement's proposed effective date; and

g. An affiliate of the Pilot Utility shall be permitted to offer and enter into third party power purchase arrangements on the same basis as may any other person that satisfies the requirements of being a seller under a third party power purchase agreement under the pilot program.

3. That § **56-585.2** of the Code of Virginia is repealed.

4. That each investor-owned utility shall consult with the Clean Energy Advisory Board established by Chapter 554 of the Acts of Assembly of 2019 in how best to inform low-income customers of opportunities to lower electric bills through access to solar energy.

5. That beginning September 1, 2022, and every three years thereafter, the Department of Mines, Minerals and Energy, in consultation with the Council on Environmental Justice and appropriate stakeholders, shall determine whether implementation of this act imposes a disproportionate burden on historically economically disadvantaged communities, as defined in § **56-576** of the Code of Virginia, as amended by this act, and shall report by January 1, 2023, and every three years thereafter, to the Chairs of the House Committee on Labor and Commerce and the Senate Committee on Commerce and Labor and to the Council on Environmental Justice.

6. That in developing a plan to reduce carbon dioxide emissions from covered units described in § **10.1-1308** of the Code of Virginia, as amended by this act, the Secretary of Natural Resources and the Secretary of Commerce and Trade, in consultation with the State Corporation Commission and the Council on Environmental Justice and appropriate stakeholders, shall report to the General Assembly by January 1, 2022, any recommendations on how to achieve 100 percent carbon-free electric energy generation by 2045 at least cost for ratepayers. Such report shall include a recommendation on whether the General Assembly should permanently repeal the ability to obtain a certificate of public convenience and necessity for any electric generating unit that emits carbon as a by-product of combusting fuel to generate electricity. Until the General Assembly receives such report,

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the State Corporation Commission shall not issue a certificate of public convenience and necessity for any investor-owned utility to own, operate, or construct any electric generating unit that emits carbon as a by-product of combusting fuel to generate electricity.

7. That it shall be the policy of the Commonwealth that the State Corporation Commission, Department of Mines, Minerals and Energy, and Virginia Council on Environmental Justice, in the development of energy programs, job training programs, and placement of renewable energy facilities, shall consider whether and how those facilities and programs benefit local workers, historically economically disadvantaged communities, as defined in § **56-576** of the Code of Virginia, as amended by this act, veterans, and individuals in the Virginia coalfield region that are located near previously and presently permitted fossil fuel facilities or coal mines.

8. That should the State Corporation Commission amend rules pursuant to the provisions of § **56-594** of the Code of Virginia, as amended by this act, it shall set forth rules for net energy metering at electric cooperatives in a new and separate chapter of the Virginia Administrative Code.

9. That nothing in this act shall require the utilities or the State Corporation Commission to take any action that, in the State Corporation Commission's discretion and after consideration of all in-state and regional transmission entity resources, threatens the reliability or security of electric service to the utility's customers.

10. That the investor-owned utility constructing a facility pursuant to § **56-585.1:11** of the Code of Virginia, as created by this act, shall provide the State Corporation Commission with reports on the facility's construction progress, including performance to construction timeline and budget, on no less than a quarterly basis throughout the construction period. The State Corporation Commission shall retain ongoing authority to review the reasonableness and prudence of any increases in the total projected cost of the RPS Program and the offshore wind facility during its construction period.

11. That by January 1, 2028, if the Secretary of Natural Resources and the Secretary of Commerce and Trade (the Secretaries) determine that the greenhouse gas reduction targets are not met pursuant to § **10-1308** of the Code of Virginia, the Secretaries shall make a recommendation to the Chairs of the House Committee on Labor and Commerce and the Senate Committee on Commerce and Labor on the necessity and advisability of a moratorium on the issuance of permits for new fossil fuel-fired generating facilities by January 1, 2030.

12. That the State Corporation Commission shall issue its final order in the Percentage of Income Payment Program (PIPP) proceeding established pursuant to § **56-585.6** of the Code of Virginia, as created by this act, by December 31, 2020, provided that the non-bypassable universal service fee shall not be collected from customers of a Phase I or a Phase II Utility, as those terms are defined in subdivision A 1 of § **56-585.1** of the Code of Virginia, as amended by this act, until such time as the PIPP is established. The Department of Housing and Community Development and the Department of Social Services shall convene a stakeholder working group and develop recommendations regarding the implementation of PIPP. Such recommendations shall allow for a utility to reimburse the administrative costs of the PIPP, not to exceed $3 million, and shall be submitted to the Chairs of the House Committee on Labor and Commerce and the Senate Committee on Commerce and Labor by December 1, 2020.

13. That this bill shall be referred to as the Virginia Clean Economy Act.

ALAN WILSON
ATTORNEY GENERAL

January 18, 2022

The Honorable Bill Sandifer, Chairman
House Labor, Commerce and Industry Committee
P.O. Box 11867
Columbia, SC 29201

Dear Chairman Sandifer:

You seek an opinion regarding a proposed "joint hearing" between the Public Service Commission of South Carolina ("PSC") and the North Carolina Utilities Commission ("NCUC"). Your concern is the scope of S.C. Code Ann. § 58-27-170 as it may apply to a proposal having been made by Duke Energy. Section 58-27-170 allows the PSC to "hold joint hearings and issue joint or concurrent orders in conjunction or concurrence" with the commission of any state or of the United States, and permits the Office of Regulatory Staff to make a "joint investigation with" the commission of any state or of the United States. Duke seeks to have the PSC employ § 58-27-170 in order to adopt a carbon reduction plan based upon a recently enacted North Carolina statute. We advise that from a legal standpoint, this proposal is fraught with problems.

By way of background, the PSC has received a joint petition filed by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Duke Energy" on November 9, 2021. You attach this Petition for our reference. Notably, there has been no request for a "joint hearing" to South Carolina by either the State of North Carolina or by the NCUC, but only by Duke Energy through the filing of the aforementioned Petition before the PSC. Such a request is unprecedented. You further state the following in your letter:

> [t]he Petition [by Duke Energy] . . . requests the Commission to hold a joint proceeding with [NCUC] . . . to develop Duke Energy's Carbon Plan as required by N.C. Gen. Stat. §§ 62-2, 62-30, Part I of Session Law 2021-165 ("HB 951"). The Petition seeks to develop a joint record through joint proceedings to develop Duke Energy's Carbon Plan. The Petition also requests that the Commission subsequently issue an order by January 31, 2023 requiring Duke Energy's Carbon Plan to be incorporated into future IRPs ("Integrated Resource Plan") to be filed in South Carolina. The Petition further requests authorization of Duke Energy's plans and associated costs to implement the plan, which if allowed would ultimately result in these costs being shared between North and South Carolina.

> I believe we need further clarification on the scope of the Commission's jurisdiction and authority over this matter which will impose North [Carolina's] legislatively mandated greenhouse costs onto Duke Energy's South Carolina customers. Specifically, I am requesting an opinion on two issues: 1) the Commission's jurisdiction to hold the requested "joint proceeding" with the NCUC and the Commission's authority to grant the requested relief, and 2) the extent of the Commission's authority to order that South Carolina ratepayers cover the costs of Duke Energy's compliance with North Carolina's legislatively mandated greenhouse gas tax on South Carolina ratepayers under HB 951.

(emphasis added).

Your letter notes your considerable concern regarding Duke's proposed "joint proceeding." Summarizing your misgivings, you state the following:

> I also question whether the Commission has the authority to order the remedy requested by the Petition—that South Carolina customers share the cost burden of Duke Energy's North Carolina legislatively mandated compliance with a carbon plan under North Carolina law (HB 951) and adopted by the NCUC. . . . In essence, the Petition requests the Commission to impose the costs of a greenhouse gas tax on Duke Energy South Carolina ratepayers through a North Carolina legislative mandate. To allow such a remedy would be an error of law, clearly erroneous, or arbitrary and capricious as directly inapposite to the Commission decision recently upheld in Duke Energy Carolinas, LLC v. South Carolina Office of Regulatory Staff, Op. No. 28066 (S.C. Sup. Ct. filed Oct. 27, 2021). There, the South Carolina Supreme Court affirmed the Commission's decision not to require South Carolina customers to pay Duke Energy's costs of complying with North Carolina's Coal Ash Management Act of 2014 ("CAMA"). . . . The Commission found that CAMA did not confer benefits to South Carolina ratepayers, and the statute was not intended to do so. Only North Carolina ratepayers benefit, and were intended to benefit, from the North Carolina legislatively mandated CAMA requirements. The Supreme Court therefore affirmed the Commission's decision to disallow the costs of compliance with CAMA in Duke Energy's South Carolina rates. . . .
>
> I further question if the requested remedy of shared cost of compliance with a North Carolina Statute is constitutional. See generally Duke Energy Carolinas, Op. No. 28066 at n.18. Under Article [X], Section [5] of the South Carolina Constitution, "[n]o tax subsidy or charge shall be established, fixed, laid or levied, under any pretext whatsoever, without the consent of the people or their representatives lawfully assembled." . . . The South Carolina General Assembly has not enacted statutes requiring actions by Duke Energy that result in increased costs to South Carolina customers. For these reasons, I question whether it is constitutional to require South Carolina customers to pay a greenhouse gas tax to comply with laws passed by the North Carolina General Assembly.

We fully agree. In our view, it is highly questionable that the Commission possesses the requisite authority and jurisdiction to convene such a "joint hearing" pursuant to § 58-27-170 for

the purposes outlined in your letter. First of all, we are aware of no instance where this statute has been employed for such a "joint hearing" since its enactment in 1932. Regardless, however, we do not think that the Commission may order South Carolina ratepayers to "cover the costs of Duke Energy's compliance with HB 951," a North Carolina statute, through utilization of § 58-27-170. The recent South Carolina Supreme Court decision in Duke Energy Carolinas, which will be discussed below, illustrates vividly that the South Carolina General Assembly has not authorized the PSC to develop a carbon plan on the basis of a North Carolina statute, pursuant to a proceeding presided over by the NCUC, and using only North Carolina law as its basis. We think that this proposal stretches South Carolina law and federal constitutional law past the breaking point. Indeed, rather than seeking a constitutionally authorized compact between the two states, such a "joint proceeding" raises significant constitutional concerns as well. Thus, to our mind, if the PSC engaged in this plan, it would run the risk of usurping the legislative powers of the General Assembly, and could well violate the state and federal Constitutions. We do not believe that current law nor the Constitution so permits.

Law/Analysis

We first examine the general authority of the Public Service Commission. Like any administrative agency, the PSC "is created by statute and its authority is limited to that granted by the legislature." Nucor Steel v. South Carolina Pub. Serv. Comm., 310 S.C. 539, 543, 426 S.E.2d 319, 321-22 (1992). Moreover, "it is well established that the Public Service Commission is a body of limited jurisdiction and has only such powers as are conferred, expressly or by reasonably necessary implication, or such as are merely incidental to the powers granted." Black River Elec. Co-op., Inc. v. Public Serv. Comm., 238 S.C. 282, 292, 120 S.E.2d 6, 11 (1961) (citing Beard-Laney, Inc. v. Darby, 213 S.C. 380, 49 S.E. 564 (1948) and Piedmont & Northern Railroad Co. v. Scott, et al., 202 S.C. 207, 24 S.E.2d 353 (1943)). In Black River, supra, the South Carolina Supreme Court concluded that the PSC lacked jurisdiction to hear, and the electric cooperative had no standing to make, a request to the Commission for a cease and desist order.

Further, our Supreme Court has consistently emphasized that:

> [o]rders issued under the powers and authority vested in the PSC have the force and effect of law. Chemical Leaman Tank Lines, Inc. v. South Carolina Public Service Commission, 258 S.C. 518, 189 S.E.2d 296 (1972). The PSC's findings of fact are presumptively correct and its orders are presumptively valid. Id. This Court will not substitute its judgment for that of the PSC upon a question for which there is room for a difference of opinion. Id. We will not set an order of the PSC aside unless it is found by a convincing showing to be unsupported by evidence or to embody arbitrary or capricious action as a matter of law. Greyhound Lines v. South Carolina Public Service Commission, 274 S.C. 161, 262 S.E.2d 18 (1980).

S.C. Cable Television Ass'n. v. Southern Bell Tel. and Tel. Co., 308 S.C. 216, 219, 417 S.E.2d 586, 588 (1992).

Yet, while South Carolina courts afford considerable weight to the Commission's rulings when it is acting within the scope of its jurisdiction or authority, such is just the opposite if the Commission exercises a power which has not been delegated to it by the General Assembly. A good example of such lack of jurisdiction is found in City of Cola. v. Pub. Serv. Comm. of S.C., 283 S.C. 380, 382, 323 S.E.2d 519, 521 (1984). There, our Supreme Court stated the following:

> [t]he respondent, however, maintains that the PSC retained the power to assign the Westville area to the Cooperative. We disagree. No statute gives the PSC such broad power. The Public Service Commission is a governmental body of limited power and jurisdiction, and has only such powers as are conferred upon it expressly or by reasonably necessary implication by the General Assembly. Glendale Water Corp. v. City of Florence, 274 S.C. 472, 265 S.E.2d 41 (1980).

In short, if the PSC lacks the jurisdiction or authority to exercise a particular power not bestowed by the General Assembly, our Supreme Court has not hesitated to so conclude.

We turn now to a discussion of § 58-27-170, upon which Duke's Petition is based. This statute reads as follows:

> [t]he commission may hold joint hearings and issue joint or concurrent orders in conjunction or concurrence with any official board or commission of any state or of the United States. The Office of Regulatory Staff may make joint investigations with any official board or commission of any state or of the United States.

Section 58-27-170 was originally enacted in 1932 as part of Act No. 871, the State's first comprehensive effort to regulate electric power. Our Supreme Court has described the purpose of Act No. 871 thusly:

> [i]n 1932 comprehensive legislation was enacted regulating electric utilities. 37 St. at L. 1497. It is frequently referred to as the Electric Utilities Act. . . . Under the terms of this legislation, the Public Service Commission is empowered to fix rates charged by electric utilities, prevent discrimination, regulate extension and development of transmission lines and otherwise supervise the operation of such utilities.
>
> The legislation was designed to require electric utilities to furnish the public, without discrimination, with adequate and efficient service at reasonable rates, and to protect such utilities from ruinous competition which was deemed an economic waste. Competition was eliminated and regulation substituted.

Black River Elec. Co-op, Inc. v. Public Service Comm., 238 S.C. supra, at 288-89, 120 S.E.2d supra, at 9.

Act No. 871 was entitled "An Act Regulating Persons, Corporations and Municipalities Engaged in the Generation, Transmission, Delivery of Furnishing of electricity for Light, Heat or Power, Prescribing the Duties of the Railroad Commission in Relations Thereto, and Prescribing Penalties for Violations of the Provisions Thereof." This Act resulted from the recommendations of the South Carolina Power Rate Investigating Committee, authorized by the 1931 General Assembly. The Act sought to level the playing field regarding power regulation in South Carolina and placed such regulation and administration of electrical power in the State under the Railroad Commission, which was ultimately succeeded by the PSC. One of the key purposes of the Act was to prevent utilities from discriminating between patrons and customers either in services or rates. See, The State Newspaper, April 9, 1932.

What became today's § 58-27-170 was found in subpart (1) of § 4 of the Act. This provision enumerated the powers of the Railroad Commission with respect to the regulation of electrical power and the utilities producing it. The original purpose of the "joint hearing" provision is not precisely clear, but we may reasonably speculate as to the General Assembly's objective. One scholar has summarized the reasons for various states' creation of such "joint hearings" provisions:

> [s]tates have presented similar proposals [for joint boards] since the 1920's, when the United States Supreme Court decided that the states lacked the authority to regulate the sale or transmission of power in interstate commerce. [see Public Util. Comm'n. of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927)]. . . . Apart from the regulatory problems that decision created (which were largely solved by the 1935 amendments to the Federal Power Act . . .), the planning aspects remain. Both in 1967 . . . and 1980, . . . federal authorities noted the need for additional regional coordination. Likewise, the states have requested federal-state coordination for nearly every major issue that was raised in the turbulent 1970's and 1980's. . . . Despite the seeming congruence between federal and state views on the need for federal regulation, little sustained effort toward that goal has occurred. . . .
>
> A partial explanation for the lack of regional regulation stems from jurisdictional limitations on state and federal authority. The states alone may not regulate the sale and transmission of electricity on a regional basis. . . . Although Congress provided for several cooperative devices, such as joint boards, conferences, and hearings, . . . to deal with the divisions of federal and state authority in the Federal Power Act, through its rules and practice the Commission has refused to use the cooperative procedures. The reasons for denying their use range from supposed jurisdictional limitations to assertions of administrative discretion. . . .
>
> But even if Congress broadened the Commission's authority, some significant institutional biases would remain because the Commission refuses to use its existing authority to create regional boards. . . . Although Congress provided for several cooperative devices, such as joint boards, conferences, and hearings, . . . to deal with the divisions of federal and state authority in the Federal Power Act, through its rules

> and practice the Commission (FERC) has refused to use the cooperative procedures. The reasons for denying their use range from supposed jurisdictional limitations to assertions of administrative discretion....

Darr, "A Critical Analysis of Joint Board Policy at the Federal Energy Regulatory Commission," 30 San Diego L. Rev. 485, 486-87(1993).

According to Professor Darr's analysis,

> [j]oint proceedings thus present a means of coordinating federal and state action since they place the parties in direct authoritative relationships with one another. Under a delegation of authority [by FERC], the state board would act as an agent of the Commission. . . . Alternatively, joint hearings would provide a forum for coordinated receipt of evidence and the opportunity for coordinated decision making. . . .

Id. at 492. Thus, such "joint proceedings" provisions have generally proven ineffective. Compare State ex rel. Clarkston v. Dept. of Public Utilities, 208 P.2d 882, 884 (Wash. 1949) [employing a similar statute to § 58-27-270 with telephone rates and the Court's noting that "a situation could arise where such action on the part of a regulatory body might be deemed to be so arbitrary or capricious or that there was such a denial of procedural due process as to make the action of such body invalid...."].

We have been unable to locate an instance in which § 58-27-170 has been invoked over the years since its enactment in 1932. Certainly, no South Carolina decision or Attorney General's opinion regarding the statute has been found. As we understand it, there have been occasions where South Carolina and North Carolina rate regulators have shared information with each other for the purpose of joint cooperation. However, no evidence of the employment of the "joint proceedings" statute has surfaced. As one study has documented,

> [c]oordination of effort with the two states was not a problem. Key reasons for this success were the strong common purpose of modeling the same utilities, the desire of the two states to act cooperatively, the mutual dependence implied by the need for data from both states, professional respect among individuals on the staffs, and the lack of conflicting model requirements. The nearly full-time dedication of the staffs and the relative absence of competing activities were instrumental in the successful completion of this joint undertaking. . . .

See Regional Regulation of Public Utilities: Issues and Prospects, at 73 (December 1980).

Based upon this background, it is our opinion that § 58-27-170 is inapplicable to this situation. First, the proposal for a "joint hearing" is not really "joint" at all. It is a proposal made to the South Carolina Public Service Commission by Duke Energy. No request from North Carolina or NCUC has been made, as far as we are aware. The intent underlying § 58-27-170 is to create a true "joint" hearing between the South Carolina Public Service Commission and

NCUC. The Petition you have forwarded would require the PSC to act unilaterally, rather than in unison with a fellow state. No such action in unison has occurred.

Secondly, we have no information that FERC is involved in this proposal. There is a strong indication that, pursuant to the Federal Power Act, FERC must participate directly or delegate authority to the states in order to avoid a "Commerce Clause" issue under the Attleboro case or other decisions. While it is true that Duke's "joint hearing" proposal is not one to directly regulate rates, as you point out in your letter, the Petition for a Joint Hearing seeks to "require that the Carbon Plan be used in the preparation of the Companies' next comprehensive IRP's" and to "confirm that the companies' plans and associated costs for the transition to be undertaken under the Carbon Plan will be fully shared and embraced between the states." Petition ¶ 20 (emphasis added). Undoubtedly, there is a strong possibility that, should the PSC authorize this "joint proceeding," the result would be to pass on a substantial portion of the costs imposed by the Carbon Plan to Duke's South Carolina customers, thereby resulting in a rate increase. In our view, this runs the risk that, without FERC's participation under the Federal Power Act, the states would be acting ultra vires and possibly in violation of the Commerce Clause.

Moreover, we also think that the "joint hearing" proposal is flawed because Duke seeks to utilize only North Carolina law in the proceeding. There can be no doubt that any proceeding in which the PSC is involved is governed by South Carolina law. As we have already emphasized in City of Cola. v. Publ. Serv. Comm. of S.C., supra, the PSC "has only such powers as are conferred upon it expressly or by reasonably necessary implication by the General Assembly." And as noted in Glendale Water Corp. of Florence, Inc. v. City of Florence, 274 S.C. 472, 474, 265 S.E.2d 41, 42 (1980), the Commission derives its powers from the South Carolina Legislature. As you recognize in your letter,

> [t]he Commission's authority to hold proceedings reviewing rates and proposed IRPs, as well as the requirements— including public posting—that Duke Energy must follow in proposing an IRP are explicitly governed under South Carolina law, including S.C. Code Ann. § 58-37-40. South Carolina has explicit statutory and regulatory procedures in place to address matters of this nature. Cost recovery issues affecting South Carolina customers are purely a matter of South Carolina law, and must be subject to a properly convened South Carolina proceeding before our Commission acting with its full authority.

The decision of the Supreme Court of South Carolina in Duke Energy Carolinas, LLC, v. South Carolina Office of Regulatory Staff, ___ S.C. ___, 864 S.E.2d 873 (2021) is highly instructive here. Not only did the Court necessarily imply that only South Carolina law could be used by the PSC, but that the PSC may not apply North Carolina law to govern South Carolina customers. In Duke Energy, Duke – the owner of a coal-fired power plant in South Carolina – sought recovery for their expenses related to their plants in North and South Carolina. Recovery of those costs were sought on a proportional share basis from their customers in the two states. The PSC, in two "lengthy and thoughtful orders, allowed in part and disallowed in part the

requested expenses." On appeal, Duke contended that the PSC "erred in disallowing (1) environmental compliance costs associated with North Carolina law"; (2) litigation costs and (3) and carrying costs. 864 S.E.2d at 875-76.

The North Carolina law involved in Duke Energy resulted from a major spill of coal ash on the Dan River. The Act, enacted by the North Carolina General Assembly, constituted the Coal Ash Management Act (CAMA), therein requiring major cleanup efforts by Duke. Duke argued that Duke's South Carolina customers should share in the imposition of CAMA costs because "in an integrated system that encompasses multiple jurisdictions, system costs are presumed to benefit the entire system, and, thus, in general customers from each jurisdiction must pay their allocable share of the system costs." 864 S.E.2d at 885.

The Supreme Court affirmed the PSC's rejection of this analysis. According to the Supreme Court,

> [h]ere, there is no evidence of any direct benefit to South Carolinians that stems from coal ash remediation costs required by North Carolina's CAMA scheme. Duke presented evidence that South Carolina ratepayers had historically enjoyed lower utility rates due to the power-generation and cost-sharing arrangement between the two states. Following the production of that low-cost power, South Carolinians paid for their pro rata share of any then-applicable environmental regulations related to disposing of the coal ash generated. CAMA, however, is a post hoc environmental remediation scheme intended by the North Carolina General Assembly to ensure the cleanliness, safety, and beauty of North Carolina's environment and the health of North Carolina's citizens. Duke's reliance on the power-generation and cost-sharing arrangement conflates the benefits of joint electricity production with the benefits of cleaning up a previously-legal, unlined coal ash pond or landfill. The environmental cleanup costs are wholly unrelated to the current production of power for which South Carolina ratepayers must pay. Had CAMA never been passed, South Carolina's ratepayers would have enjoyed the same benefits and low-cost electricity that they received after CAMA's passage.
>
> The PSC made the factual determination that the CAMA costs sought here neither directly benefitted Duke's South Carolina customers, nor were they intended to do so. There is evidence in support of this factual determination. See N. Va. Elec. Coop., Inc., 945 F.3d at 1207-08 (upholding the Commission's finding that North Carolinians did not benefit from undergrounding because the utility failed to introduce evidence to that effect, and because, in passing the undergrounding statute, the Virginia legislature intended to act for the benefit of its own citizens). We thus conclude the PSC did not commit an error of law in disallowing CAMA costs. See Utils. Servs. of S.C., Inc., 392 S.C. at 105, 708 S.E.2d at 760 (explaining that, in evaluating the evidence, the PSC is permitted to find "that some portion of an expense actually incurred by a utility should not be passed on to consumers.").
>
> Failing in its assertion of legal error, Duke next asserts the PSC's decisions regarding CAMA expenses were arbitrary and capricious. However, Duke repeatedly

> characterized this issue-whether the PSC should require South Carolina ratepayers to pay for expenses caused by another state's laws-as a policy decision, contending so at least eight times in its briefs. It is true the General Assembly designated the PSC as the expert in policy determinations with regards to utility ratemaking, and the Court does not lightly overturn those policy-based decisions. See Patton, 280 S.C. at 291, 312 S.E.2d at 259 ("The [PSC] is recognized as the 'expert' designated by the legislature to make policy determinations regarding utility rates; thus, the role of a court reviewing such decisions is very limited."). However, the issue before us is more properly characterized as a factual determination on the benefit, or lack of benefit, to South Carolina customers from CAMA related remediation costs. It appears Duke believes that by recasting the findings of the PSC as a mere policy decision, it makes it an easy leap to assert a legal error. The PSC made a factual determination that Duke's South Carolina customers did not benefit from the North Carolina-specific CAMA law. Because there is evidence to support this finding, we may not rely on contrary evidence and (assuming we were inclined to do so) substitute our view of the facts for the PSC. As we have already found, Duke has shown no such legal error.

864 S.E.2d at 885-86.

The Court's reasoning in Duke Energy is highly persuasive with respect to the questions you present here. In Duke Energy, the Court relied heavily upon the fact that application of a North Carolina statute provided no "direct benefit to South Carolinians. . . ." In other words, according to the Court, "[t]he PSC made the factual determination that the CAMA costs 'sought here neither directly benefitted Duke's South Carolina' customers, nor were they intended to do so.'" 864 S.E.2d at 415. The North Carolina carbon reduction law (HB 951), much like the CAMA statute, enacted by the North Carolina General Assembly, is a "policy" determination, and its application would require "South Carolina ratepayers to pay for expenses caused by another state's laws. . . ." Id. As in Duke Energy, this provides no benefit to South Carolina customers.

While the Court in Duke Energy did not squarely address the constitutionality of applying the North Carolina statute extraterritorially to South Carolina customers, the Supreme Court did note that it had been argued by ORS, and that the PSC had agreed, that Duke's proposal would violate Art. X, § 5 of the South Carolina Constitution, prohibiting "[n]o tax subsidy or charge shall be established, fixed, laid or levied, under any pretext whatsoever, without the consent of the people or their representatives lawfully assembled." 864 S.E.2d at 884, n. 18. In this context, the Supreme Court recited that "[t]he PSC also noted CAMA did not confer any benefits to South Carolina ratepayers, nor did the ratepayers have any opportunity to influence the North Carolina General Assembly's actions since those legislators did not represent South Carolina ratepayers." Id. The same holds true in this instance.

This argument is essentially one of "taxation without representation," based upon the extraterritorial application of a North Carolina statute to South Carolina customers with a resulting rate increase. It is the same argument in essence, that the colonists made with great

force against King George III and Parliament at the time of the American Revolution. We agree with you that, pursuant to Art. X, § 5, if the Duke proposal is implemented and does result in rate increases, such could put the Commission at risk of violating the South Carolina Constitution, as well as the federal Constitution, through the extraterritorial application of the law of another state.

It is well settled that extraterritorial laws are invalid. Our own Supreme Court has, in other contexts, recognized the invalidity of a state's application of its laws extraterritorially. The Court has stated the following:

> [t]he several states are of equal dignity and authority, and the independence of one implies the exclusion of power from all others. And so it is laid down by jurists, as an elementary principle, that the laws of one state have no operation outside of its territory, except so far as it is allowed by comity, and that no tribunal established by it can extend its process beyond that territory so as to subject either persons or property to its decisions . . . (Emphasis added). Pennoyer v. Neff, 95 U.S. 714, 24 L.Ed. 565, 568.
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> It is frequently declared that statutes can have no extraterritorial effect. By this statement it is mean that legislative enactments can only operate, proprio vigore, upon persons and things within the territorial jurisdiction of the lawmaking power, and that no law has any effect, or its own force, beyond the territorial limit of the sovereignty, from which its authority is derived. Thus, the general rule is that no state or nation can, by its laws, directly affect, bind, or operate upon property or persons beyond its territorial jurisdiction. A statute which purports to have such operation is invalid . . . 50 Am. Jur., Statutes, Section 485.
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> Under this rule, 'rather universally recognized,' . . . it is quite clear that the South Carolina statute could not affect the rights or liabilities of the parties from the North Carolina collision. No lien arose in North Carolina under the South Carolina statute, and none was created when the Pennsylvania automobile was transported into this state after the collision.

Ex Parte First Pennsylvania Banking and Trust Co. et al. v. Russell, 247 S.C. 506, 508, 48 S.E.2d 373, 374 (1966). See also Carolina Trucks & Equip. v. Volvo Trucks of North America, Inc., 492 F.3d 484, 489 (4th Cir. 2007) ["The principle that state laws may not generally operate extraterritorially is one of constitutional magnitude."]; Baldwin v. G.A.F. Seelig, Inc., 294 U.S. 571, 521 (1935) [one state may not "project its legislation" into another.]. The rule of no extraterritoriality "reflects core principles of constitutional structure" and derives in part from the structure of federalism, which is built upon 'the autonomy of the individual states within their respective spheres.'" Carolina Trucks, 492 F.3d at 490 (quoting Healy v. Beer Inst., 491 U.S. 324, 336 (1989)).

Finally, the proposal raises constitutional concerns under the federal Commerce Clause. As the Fourth Circuit explained in Carolina Trucks, the Commerce Clause guards against

extraterritorial application of one state's laws against another by precluding ". . . the application of a state statute to commerce that takes place wholly outside of the state's borders, whether or not the commerce has effects within the state. . . ." 492 F.3d at 490 (quoting Healy, 491 U.S. at 335). As the Supreme Court held in Federal Energy Regulatory Comm. v. Elec. Power Supply Assn., 577 U.S. 260, 266, ". . . the Commerce Clause bars the states from regulating certain interstate electricity transactions, including wholesale sales (i.e., sales for retail) across state lines. That ruling (Attleboro, supra, 273 U.S. at 90) created what became known as the "Attleboro gap" – a regulatory void which the Court pointedly noted, only Congress could fill."

Continuing, the Court, in Elec. Power Supply, stated:

> Congress responded to that invitation by passing the FPA in 1935. The Act charged FERC's predecessor agency with undertaking "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." New York v. FERC, 535 U.S. 1, 6, 122 S.Ct. 1012, 152 L.Ed.2d 47 (2002) (quoting Gulf States Util. Co. v. FPC, 411 U.S. 747, 758, 93 S.Ct. 1870, 36 L.Ed.2d 635 (1973)). Under the statute, the Commission has authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1).
>
> In particular, the FPA obligates FERC to oversee all prices for those interstate transactions and all rules and practices affecting such prices. The statute provides that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate transmissions or wholesale sales – as well as "all rules and regulations affecting or pertaining to such rates or charges" – must be "just and reasonable." § 824d(a). And if "any rate [or] charge," or "any rule, regulation, practice, or contract affecting such rate [or] charge[,]" falls short of that standard, the Commission must rectify the problem: It then shall determine what is "just and reasonable" and impose "the same by order." § 824e(a).
>
> Alongside those grants of power, however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction. As pertinent here, § 824(b)(1) – the same provision that gives FERC authority over wholesale sales – states that "this subchapter," including its delegation to FERC, "shall not apply to any other sale of electric energy." Accordingly, the Commission may not regulate either within-state wholesale sales or, more pertinent here, retail sales of electricity (i.e., sales directly to users). See New York, 535 U.S., at 17, 23, 122 S.Ct. 1012. State utility commissions continue to oversee those transactions.

577 U.S. at 767-68. In Electric Power Supply Association, the Court upheld a FERC rule addressing wholesale demand response, stating that:

> [t]he Rule governs a practice directly affecting wholesale electricity rates. And although (inevitably) influencing the retail market too, the Rule does not intrude on the State's power to regulate retail sales.

577 U.S. at 784 (emphasis added).

In short, the Carbon Plan proposal, outlined in your letter, in which Duke requests a "joint proceeding" pursuant to § 58-27-170, poses significant risks. Herein, we are only responding to your opinion request, not acting as an adversary to Duke, but fulfilling our legal responsibility to you as a member of the General Assembly. Nevertheless, as the South Carolina Supreme Court recognized in the Duke Energy case, supra discussed above, there was simply no benefit for "the PSC to require South Carolina ratepayers to pay for expenses caused by another state's laws. . . ." So too here. And, as the Court opined in Ex Parte First Pennsylvania Banking and Trust Co., supra, "the laws of one state have no operation outside its territory" except through comity. Thus, a court could well conclude that such a proposal constitutes "taxation without representation" in violation of Art. X, § 5 of the South Carolina Constitution. Moreover, the extraterritorial affect of the North Carolina statue in regulating Duke's South Carolina customers could be deemed to violate the principle of extraterritoriality, as well as the Commerce Clause.

Conclusion

In responding to your questions, whether the Commission possesses jurisdiction to hold the requested "joint proceeding,"; and whether the PSC has authority to order South Carolina ratepayers to cover the costs of Duke's compliance with the North Carolina statute in question (HB 951) – we seriously doubt that the answers thereto are anything but "no." This proposal is unprecedented. While we cannot resolve the legal issues presented here, we can point them out and that is what we do in this advisory opinion. The bottom line is that no statute, enacted by the South Carolina General Assembly, expressly delegates to the Commission the power to develop a carbon plan, based upon the requirements of a North Carolina statute and utilizing only North Carolina law.

While § 58-27-170 was not involved in the Duke Energy decision, discussed above, that case remains highly instructive here. As in that case, we fail to see the benefit to South Carolina customers in applying a North Carolina statute to the development of a carbon plan and imposing that plan upon South Carolina ratepayers. Rather than a benefit, such a plan, using North Carolina law, may well result in a rate increase upon Duke's South Carolina customers. In our view, employment of a "joint proceeding" does not alter that situation. The application of North Carolina law to South Carolina ratepayers is, again, unprecedented.

Further, such a proposal runs the risk of a constitutional infringement based upon Art. X, § 5 of the State Constitution. See Bradley v. Cherokee School Dist. No. One, 322 S.C. 181, 184, 470 S.E.2d 570, 571 (1996), overruled on other grounds, Home Builders Ass'n of S.C. v. School Dist. No. 2 of Dorchester Co., 405 S.C. 458, 748 S.E.2d 230 (2013) ["Where the taxing power is delegated to a body composed of persons not assented to by the people nor subject to the supervisors control of a body chosen by the people, the constitutional restriction against taxation without representation is violated."]. This is the same argument made by the colonists against

King George III and Parliament at the time of the American Revolution. Here, a "joint proceeding" which imposed rate increases, pursuant to a carbon plan, would threaten to violate Art. X, § 5.

In addition, application of North Carolina law to the "joint proceeding" could well infringe upon the constitutional principle against extraterritoriality. See North Dakota v. Heydinger, 15 F. Supp.3d 891, 910 (D. Minn. 2014), aff'd., 825 F.3d 912 (8th Cir. 2016) [Minnesota statute regulating carbon emissions, as applied to North Dakota, "violates the extraterritoriality doctrine and is per se invalid. . . ."]. No mention has been made of a constitutionally authorized compact between the two states. While the PSC undoubtedly possesses broad discretion, and it is the Commission's call to make, such a "joint proceeding" is fraught with risks. We do not believe the PSC possesses the statutory authority and jurisdiction to so act. Again, we stress that the role of the Attorney General here is to respond to the request for an advisory opinion from a member of the General Assembly, not to act as an adversary before the PSC.

Sincerely,

Robert D. Cook
Solicitor General

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

The Company discusses consolidated system operations on p. 27 thru p. 29, as well as in Appendix R. It appears that the proposed execution plan centers around system operation benefits but does not provide an execution plan for merging the two utilities.

a. Does the Company agree with this observation?
b. Please explain why an execution plan for merging the utilities should not be implemented sooner, rather than later.
c. It is the Public Staff's understanding that Duke intends to merge the DEC and DEP balancing areas, and then evaluate the potential merger of the two utilities. Is this observation correct?
    i. If so, please explain why the Companies believe this to be the appropriate path to take.
    ii. If not, please explain which path the Companies intend to pursue and why they believe it to be the proper path to follow.
d. Describe why execution plans for merging the two utilities and merging the balancing areas cannot or should not occur on parallel paths.
e. Please describe how the proposed 2022 Carbon Plan emulates or more closely resembles a joint balancing area versus historic IRP individual balancing areas.

RESPONSE:

a. Yes.

b. Merging the Carolinas utilities impacts cost allocation among jurisdictions and results in costs shifts from the wholesale jurisdiction to the retail jurisdictions, unlike Consolidated System Operations (CSO). A substantial hurdle to merging the utilities is a disproportionate shift of costs from the DEP wholesale jurisdiction to the retail jurisdiction.

c.i. The majority of CSO operations work is also needed for merging the utilities. Furthermore, consolidating operations is a foundational step to achieving carbon reduction, high renewable penetration (*e.g.*, less solar curtailments), and reliability. The project will take several years to implement and therefore, starting immediately on this work is necessary to accommodate the significant increase in solar installations and other distributed energy resources.
c.ii. Not applicable.

d. Developing execution plans for a merger is not timely until more clarity is gained regarding the direction resource planning will take in South Carolina. CSO execution plans are being developed to allow for future flexibility if merging the utilities is later determined to be most beneficial for both North Carolina and South Carolina customers and stakeholders.

e. Please see in Appendix R section "Modeling of Consolidated System Operations in the Plan" and Table R-1: Consolidated System Operations Benefits.

Responder: Nelson Peeler, Senior Vice President, Transmission and Fuels Strategy and Policy