STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1287
DOCKET NO. E-7, SUB 1261

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, for Approval of Smart $aver Solar Energy Efficiency Program In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Smart $aver Solar Energy Efficiency Program	)	COMMENTS OF THE PUBLIC STAFF

NOW COMES THE PUBLIC STAFF - North Carolina Utilities Commission (Public Staff), by and through its Executive Director, Christopher J. Ayers, pursuant to Commission Rule R8-68(d)(2), and responds to the applications (Applications) filed December 16, 2021, by Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (together, Companies), for approval of their respective Smart $aver Solar Energy Efficiency Programs (Programs).

1. On December 16, 2021, the Companies filed the Applications and requested that the Commission: (1) approve the Programs and tariffs effective January 1, 2023; (2) find that the Programs meet the requirements of a "new" energy efficiency (EE) program consistent with N.C. Gen. Stat. §§ 62-133.8 and 62-133.9 and Commission Rules R8-67 and R8-68; (3) find that the reasonable and prudent costs of the respective Programs are eligible for recovery through

each Company's annual Commission Rule R8-69(b) rider; and (4) find that the Companies are eligible to recover utility incentives and net lost revenues (NLR) pursuant to each Company's demand-side management (DSM)/EE Mechanism through the Companies' respective annual DSM/EE riders in accordance with Commission Rule R8-69.

2. On January 13, 2022, the Commission granted the Public Staff and other interested parties an extension of time until March 1, 2022, to file protests, interventions, or comments regarding the proposed Program.

3. On February 25, 2022, the Commission granted the North Carolina Attorney General's Office, the Public Staff, and other interested parties an extension of time until March 15, 2022, to file protests, interventions, or comments regarding the proposed Program.

4. The Public Staff's investigation included a review of the Applications with respect to: (a) N.C.G.S. § 62-133.9; (b) Commission Rules R8-67, R8-68, and R8-69; and (c) the Companies' respective DSM/EE cost and incentive recovery mechanisms (Mechanisms). The Public Staff's investigation also involved submission of data requests to the Companies regarding the Programs and review of the responses. Based on its investigation, the Public Staff submits the following comments for the Commission's consideration.

Program Description

5. The Programs will offer rebates/incentives to install rooftop solar photovoltaic (PV) facilities at residential premises. Solar PV systems will be limited to a capacity of no greater than 20 kilowatt (KW) alternating current (AC).

6. The Companies will offer a "Rooftop Incentive" for the installation of rooftop solar PV facilities not to exceed $0.36/watt direct current (DC); the average incentive for a participant is expected to be approximately $3,002 for DEC and $2,822 for DEP.[1] The incentive may be assigned to a customer installing solar PV or a solar leasing company with the consent of the customer. The Companies have also reserved the right in their respective tariffs to adjust the incentive prospectively, as efficiency standards and market conditions warrant.

7. In order to be eligible for the incentive, participants must:

a. Receive service on an all-electric rate schedule (all water heating, space heating, and clothes drying served by electricity);

b. Reside in individually metered single family residences, or individually metered duplexes, mobile homes, and condominiums as determined on a case-by-case basis;

c. Not be existing net metering customers or recipients of a rebate/incentive through the Companies' Solar Rebate programs;[2]

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[1] Response to Public Staff Data Request 1-36 (d), attached as Exhibit 1.

[2] Docket Nos. E-2, Sub 1167, and E-7, Sub 1166.

d. Become new net metering customers by the later of January 1, 2023, or approval of the Programs, and;

e. Enroll in the winter-focused option of DEC's Power Manager Load Control program (Rider PM), or DEP's Residential Service – Load Control Rider (Rider LC) and have an eligible thermostat ("Bring Your Own Thermostat" or "BYOT").

The Programs Are Not "New" Energy Efficiency Programs Under North Carolina General Statutes and Commission Rules

8. The Companies filed their Applications for the Programs as "new energy efficiency" programs pursuant to N.C.G.S. §§ 62-133.8 and 62-133.9, Commission Rule R8-68(c), and the Mechanism. Applications for nearly identical programs were filed with the Public Service Commission of South Carolina (PSC).[3] On January 13, 2022, the PSC issued a directive denying approval of these Applications.[4] An order explaining the basis for the denial has not yet been issued.

9. The Companies' Applications raise a threshold issue for the Commission to decide regarding the character of solar generation and capacity. Historically, solar PV capacity has been treated as renewable generation. The subject Applications now turn this concept on its head.

10. N.C.G.S. § 62-133.8(a)(4) defines an "energy efficiency measure" as:

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[3] PSC Docket Nos. 2021-143-E and 2021-144-E, https://dms.psc.sc.gov/Attachments/Matter/9102b2d5-fdd6-4411-a3e3-d16689c42fde

[4] Exhibit 2, https://dms.psc.sc.gov/Attachments/Matter/0562aa4c-6e03-4367-b34d-05861af5492c.

> an equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources.

Except for the expressed inclusion of combined heat and power (CHP) as an EE measure, North Carolina's definition of EE is consistent with that of the U.S. Energy Information Administration (EIA), which states:

> Energy efficiency, Electricity: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in mega-watt hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.[5]

11. The Companies' current portfolios of approved EE programs provide incentives to encourage customers to install equipment that operates more efficiently (i.e., providing the same level of functionality while using less energy to do so), thus lowering the amount of electricity consumed in the home. For example, the Companies are currently providing incentives to customers to install higher Seasonal Energy Efficiency Ratio (SEER) rated HVAC equipment or to purchase specialty LED lighting technologies. These end-use enhancements in HVAC and lighting technology keep the home just as warm or cool, or just as bright or brighter

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[5] https://www.eia.gov/tools/glossary/

as less efficient equipment. By maintaining the same functionality while consuming less energy in the process, it is clear each of these measures is EE. The Commission has approved numerous requests for new or modified EE programs because the Companies demonstrated that less energy would be cost effectively consumed by the end use, consistent with the statutory definition of EE.

12. Solar PV generation is defined in N.C.G.S. § 62-133.8(a)(8) as a "renewable energy resource." The defining characteristic is that solar PV generation produces electricity that is derived from a renewable energy resource. It does not reduce the amount of energy consumed by any end-use. These fundamental characteristics have not changed since N.C.G.S. § 62-133.8 was adopted by the General Assembly in 2007.

13. Unlike higher-SEER HVAC and LED light bulbs that clearly are EE measures, CHP was specifically classified as an EE measure in N.C.G.S. § 62-133.8(a)(4). CHP does not fit into the general definition of EE (less energy used to perform the same function), as it produces electricity or thermal energy instead of reducing energy consumption. Nevertheless, the statute specifically provides for its inclusion in the definition of EE. The Commission has approved CHP as an EE measure in both DEC's and DEP's EE portfolios.[6]

14. The Commission also expressly addressed the character of CHP and clarified what constitutes an EE measure in its February 29, 2008 Order Adopting Final Rules in Docket No. E-100, Sub 113. That Order states on page 86:

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[6] CHP is presently part of the Companies' respective Non-Residential Smart $aver Performance Incentive Programs (Docket Nos. E-7 Sub 1032 and E-2 Sub 1126).

> On a careful reading of the law, the Commission does not agree with the Public Staff that there is a danger of gaming resulting from reliance on CHP systems. G.S. 62-133.7(b)(2)c explicitly states that, to meet its REPS obligations, an electric public utility may "[r]educe energy consumption through the implementation of an energy efficiency measure." Therefore, as an EE measure for REPS compliance, **the electric public utility must "reduce energy consumption."** The use of some measure of waste heat recovery in a CHP system would not allow all of the power generated by that system to qualify for REPS compliance unless the power were generated through the use of a renewable energy resource. **The only benefit that can be claimed in the EE part of REPS is energy actually saved."** *[Emphasis added.]*[7]

Thus, like CHP, rooftop solar does not reduce the customer's energy consumption, rather it generates power.

15. N.C.G.S. § 62-133.8(a)(4) has not been modified since it was enacted. No party, including the Companies, has proposed any modification to Commission Rule R8-67(a)(1) or (3). However, Section 7.(e) of the third edition of House Bill 951[8] (HB 951) would have amended the statutory definition of EE. That proposal stated:

SECTION 7.(e) of the draft for N.C.G.S. 62-133.8(a) reads as rewritten:

> (a) Definitions. – As used in this section:
>
> (4) "Energy efficiency measure" means an equipment, physical, <u>behavioral,</u> or program change implemented <u>by a retail electric customer</u> after January 1, 2007, that ~~results in less energy used~~ <u>reduces the customer's energy requirements from the electric power supplier needed</u> to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy

[7] "REPS" means "Renewable Energy and Energy Efficiency Portfolio Standard," as defined by NC Gen. Stat. § 62-133.8.

[8] Exhibit 3, https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v3.pdf. The Third Edition was passed by the North Carolina House on July 15, 2021. The Conference Committee Substitute that was ultimately enacted removed these provisions and added a provision that "[e]xisting law shall apply with respect to energy efficiency measures and demand side management." S.L. 2021-165, Section 1, (1)a.

> produced from a combined heat and power system that uses nonrenewable energy ~~resources.~~ Resources, and energy produced by a customer generator as that term is defined under 62-126.3(4). "Energy efficiency measure" does not include demand-side ~~management.~~ Management or the net monthly exports of energy by a customer under a tariff approved pursuant to G.S. 62-126.4(b).

Section 6.(a) of the third edition of HB 951 also included revisions to N.C.G.S. § 62-126 that included the following definition:

> (4) Customer generator. – An owner, operator, or customer-generator lessee of a solar energy facility or other renewable energy facility, including any equipment that enhances the use of that facility such as an energy storage device, provided that the storage device is charged solely from that facility, that is taking service under the terms and conditions of a net metering tariff approved by the Commission, including a tariff authorized under 45 G.S. 62-126.4A.

If ultimately approved, these revisions would have replaced the requirement that implementation of an EE measure "result in less energy used" with an alternative requirement that the customer's energy requirements from the electric power supplier be reduced. It also would have added solar generation from a customer generator to the sentence in the definition that specifically defines CHP as EE. If this version of HB 951 had been enacted, the proposed Programs would have met the definition of EE in North Carolina. Ultimately, these amendments were not included in the final version of the bill, which was enacted into law as S.L. 2021-165. Therefore, the General Assembly maintained the clear and unambiguous statutory definition of EE: except as otherwise specified, an EE measure is defined as an equipment, physical, or program change that when implemented results in less use of energy to perform the same function.

16. A statute that is clear and unambiguous must be given its plain and definite meaning.[9] The "utility savings" produced from the proposed Programs are not a measurement of reduced household electricity consumption, rather they are a measurement of the amount of electricity generated by the solar facility to replace the electricity no longer being purchased from the Companies. The home's total electricity needs remain unchanged. In more simple terms, the customer-owned solar PV generation is a substitute for energy that would otherwise be purchased from the Companies to supply the total electricity needs of a home. This is clearly and unambiguously not EE as it is defined by statute.

17. In deciding what is included in the definition of an EE measure, the Commission cannot insert or delete words in the statute.[10,11] The General Assembly did not specifically include customer-sited solar generation as an EE measure, as it did for CHP systems. If the General Assembly had intended to include solar generation as an EE measure, it was within its power to write N.C.G.S. § 62-133.8(a)(4) in that way, but it did not do so.[12] Unless customer-sited solar generation, or any other form of customer-owned or sited generation, is

[9] *State ex rel. Utils. Comm'n v. N.C. Sustainable Energy Ass'n*, 254 N.C. App. 761, 764 (2017) (CHP Decision), quoting *In re Banks*, 295 N.C. 236, 239, 244 S.E.2d 386, 388-89 (1978) (citing *State v. Camp*, 286 N.C. 148, 152, 209 S.E.2d 754, 756 (1974)); *see also* *State ex rel. Utils Comm'n v. Env't Def. Fund*, 214 N.C. App. 364, 366, 716 S.E.2d 370, 372 (2011).

[10] See *Id.*, citing *Lunsford v. Mills*, 367 N.C. 618, 623, 766 S.E.2d 297, 301 (2014).

[11] In its definition of an EE measure in Commission Rule R8-67(a)(3), the rule adds "or provide the same level of service" to the statutory definition. ("Energy efficiency measure" means an equipment, physical, or program change that when implemented results in less use of energy to perform the same function or provide the same level of service.) The addition of this phrase cannot be construed to alter or amend the statutory definition but must be consistent.

[12] With regard to CHP, the NC Court of Appeals found in the CHP Decision that if the General Assembly "had intended only for the waste heat component of a CHP system to qualify as an energy efficiency measure, it was within the power of the legislature to write N.C.G.S. § 62-133.8(a)(4) in that way, but that is not the law as written by our General Assembly."

expressly included in the definition of EE by the General Assembly, as it was in the third edition of HB 951 that was ultimately rejected, the Programs are not EE programs.

18. In these Applications, the Companies use the phrase "reduced energy consumption from the grid," which is a phrase that appears never to have been used before by either Company in previous EE applications, DSM/EE rider proceedings, or any other Commission proceedings. The phrase stretches the definition of EE beyond what is clearly laid out in statute.

19. There is a distinct difference between the statutory definition of EE in N.C.G.S. § 62-133.8 (a)(4) ("…that results in less energy used to perform the same function"), and the Companies' use of a phrase absent from the statutory language ("…reduced energy consumption from the grid"). Consider a residential customer who owns a 15-plus-year-old heat pump with a SEER rating of 13 or less. As of 2022, the baseline efficiency standard for heat pumps is SEER 15 and greater.[13] If the customer installs solar PV generation as a participant in these Programs, the customer's heat pump would use electricity generated by their solar PV system during times when the solar PV system is producing electricity. Alternatively, that same heat pump would use energy from the grid when the solar PV system is not producing sufficient amounts of electricity to serve the heat pump. There has been no change in the physical condition of the customer's home or the equipment used within the home. Even if paired with a higher SEER heat pump, the level of efficiency the customer would experience remains the same regardless

[13] https://www.energystar.gov/products/heating_cooling/heat_pumps_air_source/key_product_criteria

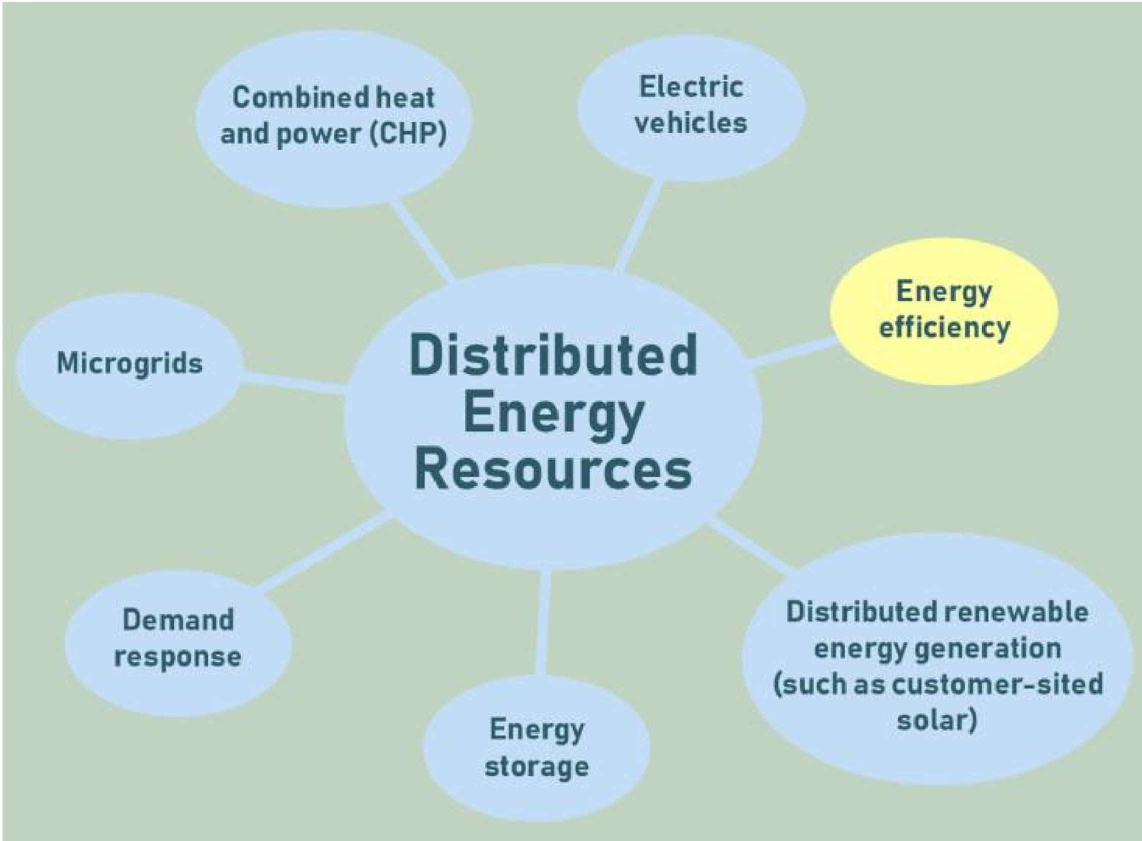
of the source of electricity. Simply replacing the source of the energy does not make it EE.

20. Another clear distinction between distributed generation and EE is found in Section 4(a) of HB 951 in the definition of “Distributed Energy Resource.” The definition as ratified states:

> G.S. 62-133.16 (a)(3) "Distributed energy resource" or "DER" means a device or measure that produces electricity or reduces electricity consumption and is connected to the electric distribution system, either on the customer's premises or on the electric public utility's primary distribution system. **A DER may include any of the following: energy efficiency, distributed generation,** demand response, microgrids, energy storage, energy management systems, and electric vehicles. *[Emphasis added]*

The definition makes an obvious distinction between EE and distributed generation along with other possible resources. However, it does not make EE distributed generation, nor does it make distributed generation EE.

21. The American Council for an Energy Efficient Economy (ACEEE) also recognizes the distinct differences in EE, renewable energy resources, and storage in the illustration below:



Source: "Integrating Energy Efficiency, Solar, and Battery Storage in Utility Programs," Rohini Srivastava, February 2020, Report No. B2001. https://www.aceee.org/research-report/b2001

ACEEE in this report distinguishes EE from other resource types as it describes DERs:

> Energy efficiency is a DER insofar as efficiency measures reduce a building's energy use and therefore the overall demand on the system. Other DERs include demand response, distributed renewable energy generation (such as customer-sited solar), energy storage, microgrids, combined heat and power (CHP), and electric vehicles.

Additionally, FERC Order 2222[14] makes a similar distinction in its definition of EE and its association with DERs:

> We define a distributed energy resource as any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.

22. The Companies' Applications also compare the Programs to the now canceled Solar Thermal Water Heating Program (SWHP) that was offered as an EE pilot by DEP in Docket No. E-2, Sub 937. The SWHP was approved as a pilot to assess the program costs, level of demand and energy savings, and cost effectiveness. More specifically, the purpose of the pilot was to assess the cost effectiveness of reducing the total electric energy required to produce hot water, as compared to an average home using an electric water heater. This would be accomplished by using solar thermal energy to replace electricity to produce hot water. Ultimately, the SWHP was found not to be cost effective and was canceled.[15]

23. By utilizing the sun to generate thermal energy to heat the water, as opposed to a solar PV system being used to generate electricity, the SWHP was considered to be an eligible EE measure consistent with the statutory definition. Unlike a solar PV system, the solar water heating technology did not generate

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[14] See page 4 of FERC Order 2222, issued on September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

[15] See page 9 of Robert P. Evans Supplemental Testimony filed August 15, 2013, in Docket No. E-2 Sub 1030. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4acecdd3-28f6-48dc-aad9-2140b2374e52.

electrical energy, thus less electricity was used by the end-use equipment to perform the same function. Moreover, a solar rooftop PV system does not reduce the energy consumption of any particular equipment or end-use; it merely replaces electric energy that otherwise would have been obtained from the utility. While it is true that solar PV reduces the customer's demand for energy from the utility, it does not change the end-use of energy by the customer. It is this end-use of energy that is the heart of EE.[16, 17] In fact, a customer's energy consumption could very well increase, but when netted against the production of the solar PV array, the overall demand from the customer could be reduced. While ultimately both EE measures and customer solar generation may result in a reduction of demand, they should not be conflated.

There are Significant Differences between EE and Solar PV Generation

24. The Commission's September 14, 2011 Order Denying Approval of Program[18] of Dominion Energy North Carolina's proposed Commercial Distributed Generation Program in Docket No. E-22, Sub 466, is instructive. Under the proposed program, Dominion commercial and industrial customers would receive an incentive for committing backup generation for dispatch in response to load control events. On page 4 of its Order, the Commission found that the program was designed "to incent the construction of new generation, albeit ostensibly by

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[16] Notwithstanding the North Carolina statutory definition of EE, other definitions of EE distinguish it as an end-use of energy. See the EIA's explanation at https://www.eia.gov/energyexplained/use-of-energy/efficiency-and-conservation.php.

[17] https://www.epa.gov/sites/default/files/2018-07/documents/mbg_1_multiplebenefits.pdf.

[18] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9f68c7c8-478b-4e50-aed6-72ed026c0328

customers rather than the utility." While the Programs differ in that they are incenting customers to install emission-free, renewable solar PV generation instead of fossil fuel generation, the principle is the same. Incentivizing the installation of solar PV has been recognized by the General Assembly as a desirable policy goal via the Solar Rebate program, and by the Commission in the SunSense solar incentive program, Docket No. E-2, Sub 979, which is discussed in the next section. However, neither program is an EE program.

25. Solar generation without storage is an intermittent resource that necessitates additional utility investments to its transmission, distribution, and generation systems (or the retention of already existing investments) to serve the total potential energy requirements of the home when the customer-owned solar PV system is not producing energy. The Programs offer quite a different scenario from a traditional EE measure that reduces load incrementally, while achieving the same level of function. In other words, the total load connected to the grid does not change with the installation of customer-owned solar PV generation, and, as a result, the utility must stand ready to supply this load at any time, including on cloudy or rainy days and at night.

26. The distinction between what constitutes a renewable energy credit (REC) and energy efficiency credit (EEC) for REPS compliance purposes also has bearing on the consideration of the Programs as EE measures. Solar energy generation is specifically listed as one of several renewable energy resources in N.C.G.S. § 62-133.8(a)(8). It was also given some preference by the General

Assembly through the set-asides for preferred renewable generation.[19] Thanks to Session Law 2007-397 (SB3), solar energy in North Carolina has become a fundamental component of the Companies' mix of generation resources, and customers with the economic means to install solar PV on their homes have installed many MWs of solar PV capacity. Much of the solar PV has been installed without utility incentives.

27. Another critical distinction between what constitutes a REC versus an EEC is the determination of the type of certificate or credit that will be realized. The tariff filed as Attachment G to each Application states that "upon payment of these considerations, Company will be entitled to any and all environmental attributes, including but not limited to 'renewable energy certificates (RECs), 'renewables energy credits' or 'green tags,' associated with the solar PV generation system…" It is apparent from the language in the tariff itself that consideration was given to the fact that solar PV systems produce RECs, not EECs. The Companies have routinely included similar language in many of their EE program tariffs. One example illustrating the similarities is DEC's Residential Energy Efficient Appliances and Devices tariff:[20]

> COMPANY RETENTION OF PROGRAM BENEFITS Incentives and other considerations offered under the terms of this Program are understood to be an essential element in the recipient's decision to participate in the Program. Upon payment of these considerations, Company will be entitled to any and all environmental, energy efficiency, and demand reduction benefits and attributes, including

[19] N.C.G.S.§ 62.133.8(d) establishes set-aside requirements for a certain percentage of energy sales to be derived from solar energy resources.

[20] https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/rates/electric-nc/nceeresappdev.pdf?la=en&rev=07f869db26b249d7a7c573f5fb8b6af3

all reporting and compliance rights, associated with participation in the program.

<u>**The Programs are Continuations of the Solar Rebate Programs**</u>

28. The Programs are very similar to the SunSense program offered by DEP. In that program, DEP offered customers that installed rooftop solar an upfront rebate and a monthly credit in return for the customer's RECs, which would assist DEP in meeting its REPS requirements. DEP recovered the costs of the program through its REPS rider. However, DEP never sought approval of the SunSense program as an EE program pursuant to Commission Rule R8-68 in either the initial application filed July 1, 2010, or its January 22, 2013, and August 22, 2014, requests to revise the program, which were approved. Moreover, the Company did not seek to recover lost revenues or receive a utility incentive for offering the program.

29. The SunSense program was approved in the very early stages of implementation of SB3. DEP requested initial incentives of $1.00 per watt AC as an upfront incentive, with a monthly credit of $0.45 per watt AC based on the capacity of the rooftop solar PV system. The upfront incentive was subsequently lowered to $0.50 per watt AC in 2013 in response to the burgeoning market for renewable energy derived from solar PV systems. DEP stated in its request to modify the incentive that the Company "believes the lower upfront rebate reflects recent dramatic declines in the cost of solar."[21] A subsequent request to reduce

[21] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=342f0803-c863-4135-b612-04e880a6c680

the upfront incentive further to $0.25 per watt AC was approved November 12, 2014.[22]

30. In Paragraph 5 of each Application, the Companies include a footnote stating in part, "Pursuant to N.C. Gen. Stat. § 62-155, the Company's Solar Rebate Program comes to a close on December 31, 2022, prior to the effective date of this proposed program." With the Programs having an effective date of January 1, 2023, approval of the Programs would allow the Companies to continue offering solar rebates. This timing is not coincidental. The closure of the Solar Rebate Program will occur as a result of the statutory sunset provisions in N.C.G.S. § 62-155. The Companies' Applications are clearly intended as a continuation of the Solar Rebate Program, albeit in another form that not only offers incentives for customer-owned residential solar PV systems, but also will allow Duke to receive the utility incentives of: (a) NLR; and (b) a Portfolio Performance Incentive (PPI) for electric energy the Companies do not have to produce. As represented in the Applications, the estimated NLR for the first five years for DEC and DEP are estimated to be $39,457,165 and $30,937,677, respectively. Notably, the Companies expect the NLR paid to them to exceed the amount of incentives that will be paid to customers. DEC and DEP project that the cost of incentives paid to customers will constitute approximately 38% of the total program costs and NLR; as of March 2021, the Solar Rebate programs have cumulatively spent approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Thus, the sunsetting of the Solar

[22] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f4e96c44-f670-46d8-89b0-25d3a4945944

Rebate Programs would be replaced with similar solar rebate programs[23] that provide similar results, but with additional revenue streams to the Companies in the form of NLR and PPI.

31. The Programs also require participation in the Companies' respective Winter BYOT DSM programs. The Companies have asserted to the Public Staff that neither of the Applications include any costs or savings that would be attributable to the Winter BYOT programs. In fact, the Companies seem to have made great effort in their analyses and modeling to ensure that the savings attributable to the Winter BYOT programs are not counted in savings attributable to the Programs and vice versa. The Companies are relying on the Programs to promote cross-participation in Winter BYOT and have asserted that tying participation in the Programs to Winter BYOT participation for a 25-year period will help to improve the participation of Winter BYOT. Regardless of this relationship between the Programs and Winter BYOT, tying the Programs to the Winter BYOT program does not transform the Programs from solar rebate programs into DSM/EE programs, nor does it alter the statutory definition of EE.

32. Based on the arguments above, the Public Staff recommends that the Commission deny the Applications on the basis that the proposed Programs fall outside of the statutory definition of EE and should not be considered as EE programs but as solar rebate programs.

[23] The current rebate available to residential customers under the Solar Rebate Program is $0.40 per watt, which is very similar to the proposed $0.36 per watt rebate proposed in this docket.

Other Considerations

33. Should the Commission find otherwise, the Public Staff brings the following aspects of the Programs to the Commission's attention.

Lengthy Commitment Period

34. The Programs would require the participating customer to make a 25-year enrollment commitment with its respective provider. Should the participant end its participation in the Winter BYOT program early, the participant will be required to return a prorated share of the rooftop solar incentive. In addition, if the customer opts out of more events than the Winter BYOT program allows in a year, the customer will be charged a $200 fee representing an annualized, prorated share of the rooftop solar incentive.

35. The Applications are the first time that the Companies have proposed a contract/commitment length to match the equipment's measure life. Previously, EE measures have not required customer commitments to an EE program beyond the initial installation of the measure. The measure life was simply a means of defining the length of time that savings would be generated from a measure. The eligibility requirements commit a participant of one program to also participate in another program (Winter BYOT DSM program). The attempt to capture synergies by requiring cross-participation in other EE programs is a novel idea. However, these synergies have previously been accomplished on a voluntary rather than compulsory basis with a much shorter commitment period. DSM programs like BYOT are no exception. For example, the Power Manager and EnergyWise

programs require only one-year annual commitments from participants. Even for non-EE/DSM solar PV programs like the Solar Rebate Rider and the SunSense program, the Companies have required contracts that last no longer than 10 years.

Cost-Effectiveness

36. N.C.G.S. § 62-133.9(c) and Commission Rule R8-68 require the Companies to provide information regarding the estimated cost effectiveness of the Programs. In particular, Commission Rule R8-68(c)(2)(iv) provides that an electric public utility filing for approval of a DSM or EE measure must provide economic justification for each proposed measure or program, including the results of at least four cost-effectiveness tests: the Total Resource Cost (TRC) test, the Utility Cost (UC) test, the Ratepayer Impact Measure (RIM) test, and the Participant Cost (PC) test.

37. The Public Staff reviewed the calculations associated with the cost-effectiveness evaluation supporting the Applications. Attachment B to the Applications provides the estimated costs and benefits over the life of the Programs. Two key facts bear mentioning from this analysis.

Free Ridership

38. One consideration in determining cost-effectiveness is free ridership, which occurs when a customer installs an EE measure without any program incentives but receives a financial incentive or rebate anyway. Free ridership is an important element in the Commission's determination of whether the Programs are in the public interest. Free ridership, as a component of the Net-to-Gross

calculation, provides a sense of the overall need of a program. As free ridership increases, the need for an incentive program diminishes. This process is viewed as market transformation. As the market becomes more willing to adopt a new technology without the intervention of the utility, the need to incentivize that technology becomes less necessary.

39. The Company's initial estimate of free ridership (10%) is not based on national data, other utility data, Company data, or other technical reference manuals or evaluation, measurement, and verification (EM&V). The Companies stated in a data response that it assumed a 10% free ridership for the Programs because it did not have a similar program to use for comparison. The Companies stated that they presumed the percentage was above zero but chose to be conservative by using 10%.

40. In the Companies' Solar Rebate Programs, many customers installed solar PV generation even though they were denied an incentive through the Solar Rebate Programs. The table below shows the number of customers that applied for the solar rebate but were not accepted, and the percentage of those applicants that installed a solar PV system on their residence despite not receiving the rebate.

DEC & DEP Combined	**2018**	**2019**	**2020**	**2021**
Applicants Not Accepted	156	1385	1764	2721
Not Accepted But Still Connected	94%	96%	93%	93%

41. While the Companies have stated that there is not a similar program with which to compare performance to determine free ridership, the Public Staff

believes that this data can be used to establish a proxy for the percentage of free ridership that may be experienced by the Programs. When comparing the data on Solar Rebate Rider participation, the annual participation ranged between 1,000 and 2,000 customers, which is consistent with the incremental participation projections that the Companies modeled in the Applications for the first five years of the Programs. Additionally, the incentive structure of the Solar Rebate Rider is very similar to the incentive structure of these Applications. Because there are no other Solar as EE programs being offered in the country to the Public Staff's knowledge, the data provided on the Solar Rebate Rider is a reasonable proxy for the percentage of free ridership until further data can be obtained through EM&V.

42. To elaborate on the impact of applying a more accurate proxy of the free ridership percentage to the Programs, assuming all other cost and benefit assumptions are the same, the Public Staff applied a 90% free ridership rate (consistent with the above assumed free ridership percentages from the solar rebate program), which results in cost effectiveness scores for the Programs as follows:

DEP			
Free Ridership: 90%		NTG: 10%	
UCT	TRC	RIM	Participant
0.25	0.05	0.10	0.07

DEC			
Free Ridership: 90%		NTG: 10%	
UCT	TRC	RIM	Participant
0.31	0.06	0.13	0.07

As seen in the tables above, using what the Public Staff believes to be more accurate free ridership rates indicates that the Programs would not be cost effective under any of the four tests and, even if allowed to be considered as EE programs, quite likely would be ineligible for approval. In fact, again assuming all other cost and benefit assumptions are the same, the lowest free ridership percentage that would still produce a positive UC test result for the Programs would be 60% for DEP and 67% for DEC, significantly above the 10% assumed by Duke.

DEP			
Free Ridership: 60%		NTG: 40%	
UCT	TRC	RIM	Participant
1.01	0.20	0.41	0.30

DEC			
Free Ridership: 67%		NTG: 33%	
UCT	TRC	RIM	Participant
1.02	0.20	0.43	0.23

43. In the Solar Rebate Programs, the deployment of solar PV generation by customers who did so despite receiving no incentive, indicates that there is much higher free ridership than 10%. This is certainly the case when considered with the Participant test scores discussed below, which suggests residential customers are deploying solar PV generation regardless of incentives.

44. The discussion above regarding the SunSense Program suggests a similar conclusion. It was clear even a few years ago that incentives should be

decreased, in tandem with the decreases in the costs per watt of solar PV generation.

Costs Outweigh the Benefits for Participants

45. Even when using the Companies' estimates of free ridership, of the four cost-effectiveness tests, with the exception of DEC's RIM test, the Programs only pass the UC test, and this occurs because the Companies' modeling considers the energy savings to be the difference between grid-supplied energy and customer-supplied energy.

	UCT	TRC	RIM	PCT
DEC	2.72	0.81	1.12	0.88
DEP	2.24	0.67	0.91	0.87

46. Pursuant to the Mechanisms, the primary test for program cost effectiveness is the UC test. However, the other three tests provide valuable insight as to who the Programs will benefit. Based on the cost tests provided, the PC test is below 1.0, meaning that the Programs do not financially benefit the participating customer, a result worth noting as that has never been seen to the Public Staff's knowledge for EE programs approved by this Commission, and is also further evidence that incentives are not a deciding factor for many participating customers.

Net Lost Revenues and PPI

47. The Companies' DSM/EE Mechanisms set out the conditions under which the Companies may recover NLR resulting from EE programs.[24] As illustrated on Attachment B of the Applications, the estimates of NLR are $39,860,796 and $27,740,167 (net of fuel) for DEC and DEP, respectively.

48. The Companies state in their Applications that they seek approval to include the recovery of program costs and utility incentives for the Program in their annual DSM/EE rider proceedings. This would allow the Companies to recover program costs, NLR, and PPI for electricity that was both produced and consumed by the same customer, while simultaneously charging that customer retail electricity rates for service to back up that customer when the custom-owned solar PV is not producing electricity. There is precedent for denying a PPI under these circumstances. DEP is not allowed to receive a PPI associated with its Distributed System Demand Response EE Program (DSDR).[25]

Evaluation, Measurement, and Verification

49. The Companies propose to use an independent third-party consultant to implement their EM&V plan, but they have not yet hired the consultant to perform the EM&V work for the Programs, nor developed an evaluation plan that would guide the evaluation.

[24] For DEC see paragraphs 60 through 64. For DEP see paragraphs 66 through 69.

[25] DSDR is a unique EE program that provides system-wide reductions of voltage and energy on the distribution system. DSDR is also wholly on DEP's side of the meter and is totally within its control to use. The costs of DSDR are allowed to be recovered from all residential and non-residential customers who are subject to the DSM/EE riders.

50. While it is often the case that the Companies have not hired a third-party evaluator or developed an evaluation plan at the time of an EE program application, EM&V of this unconventional program will require considerably more study and effort. Duke certainly has experience in assessing the output from both large and small solar PV generation facilities. However, interpreting energy data from solar PV systems as part of an EE program appears to be a new endeavor for the EM&V community. Unlike a new HVAC or lighting program, where evaluators have numerous reports to compare their evaluation process, this level of work would be unique to North Carolina. Typical EM&V would assess the efficacy of EE measures using an engineering analysis of pre- and post-installation or a billing analysis that tested the basis for, and the reasoning behind, the adoption of the EE measure by the customer. Such an exercise is designed to understand whether the savings resulted from adoption of the measure. There is no information as to how the Programs would be evaluated, what would constitute "energy savings" eligible for REPS compliance as EE, or the cost of the EM&V.[26]

Potential for Fuel Switching

51. Incentivizing the installation of rooftop solar PV generation, as the Companies have proposed, could affect a customer's decision to install natural gas over electric service because the Programs are open only to customers on an all-electric rate. In response to a Public Staff data request, the Companies stated that the requirement for all-electric service was intended to maximize the cost-

[26] Should the Commission approve the Programs, the Companies should file this information within 90 days of the Commission approval order.

effectiveness of the Programs. Approximately 59% of DEC's residential customers are gas-electric customers. The percentage of DEP's customers that are all-electric is unknown.[27]

52. While maximizing cost-effectiveness is an important consideration, the ineligibility of customers that may choose to install natural gas appears to be unreasonably discriminatory pursuant to N.C.G.S. § 62-140. The Public Staff believes that if approved by the Commission, the Programs should be offered to all customers and not bar a substantial percentage of residential customers from participation. This approach would be consistent with the Companies' previous and current solar rebate initiatives, where all customers are eligible to participate.[28]

Conclusions and Recommendations

53. In conclusion, the Public Staff recommends that the Commission deny the Applications on the basis that they are inconsistent with the statutory definition of EE. Should the Commission determine that the Programs are consistent with the statutory definition of EE, the Public Staff recommends that the Programs be approved as pilot programs in effect for three years beginning January 1, 2023, subject to the following conditions:

a. the Companies show them to be cost-effective net of free riders;

[27] Determined as a percentage of billing units from the Compliance Filing workpapers in Docket No. E-7, Sub 1214. DEP does not distinguish between all-electric and gas-electric customers in its retail rate schedules.

[28] If expanding eligibility for the Programs to all customers makes them no longer cost-effective under the UCT, then they should not be offered at all.

b. the Companies be denied recovery of NLR and a PPI;

c. the Companies modify the commitment length to 10 years to be consistent with the commitment length of the solar rebate programs;

d. the Companies file within 90 days of approval the name of the third-party EM&V consultant, an evaluation plan, the costs of EM&V, and what would constitute "energy savings" eligible for REPS compliance as EE; and

e. the Companies modify the eligibility requirements to allow the Programs to be offered to all residential customers regardless of fuel source.

54. The Public Staff has supported programs such as the Solar Rebate Programs and SunSense that incentivized the installation of rooftop solar and will continue to do so when the programs are cost-effective and in the public interest. But the Solar Rebate Programs and SunSense were not offered as EE programs, which may include recovery of NLR and PPI. As the Programs are at heart solar rebate programs, the Public Staff recommends that the Commission deny the Applications and require Duke to evaluate whether a traditional solar rebate program could assist it in achieving its Carbon Plan requirements **in a least-cost manner**.

Respectfully submitted this the 15th day of March, 2022.

PUBLIC STAFF
Christopher J. Ayers
Executive Director

Dianna W. Downey
Chief Counsel

Electronically submitted
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CERTIFICATE OF SERVICE

I certify that a copy of this Response to Petition for Approval of Programs has been served on all parties of record or their attorneys, or both, in accordance with Commission Rule R1-39, by United States Mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 15th day of March, 2022.

Electronically submitted
/s/Lucy E. Edmondson
Staff Attorney

CONFIDENTIAL

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

The following questions are related to the attachments to the Applications:

a. Please provide workpapers and supporting calculations in Excel format (with all links and formulas intact, including all linked worksheets and workpapers) for the data (number of participants, program costs and their constituent costs, avoided energy and capacity cost benefits, energy and capacity savings, per unit avoided costs used to determine the avoided cost benefits, rate period costs, lost sales, participant incentives, utility incentives, etc.) contained in each attachment included in the filing. Also, include any reconciliation between the attachments necessary to more fully understand the linkage of data in the attachments.

b. The attachments illustrate the attributes of the Solar EE Program over a period of 5 years. Given the 25-year commitment of participants to the Solar EE Program and Winter BYOT Program, please either provide the projection of program attributions for a 25-year period or provide an explanation of the expected impacts/changes to the projections for years 6 through 25.

c. With respect to the estimated number of participants in Attachment A, please provide the methodologies and sources used to develop the projection of participants, including any copies of market potential studies or any outside sources or projections the companies used to develop these projections.

d. Please provide the average incentive expected per participant.

e. Please provide support for the 10% Free Ridership (line 2 of Attachments A).

f. Please define the term "participant" as used in the attachments.

g. If different from the previous question, please identify the participant in the Participant Test in Attachment B of both Company's applications.

h. Please explain whether the information included in the attachments represents total system operations, or just the North Carolina retail. If this is not only North Carolina retail operations, please specify the North Carolina retail portion for each attachment and include a description of the allocation factors used to develop each attachment.

CONFIDENTIAL

NC Public Staff
Docket No. E-2, Sub 1287 and
E-7, Sub 1261
Solar as EE Programs
NC Public Staff Data Request No. 1
Item No. 1-36

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request (cont.):

i. Please provide the assumptions regarding the amount of capacity and energy savings from the Program to calculate the cost effectiveness of the Program as given in Attachment B.

j. Please identify the cost items and amounts that comprise the $11,298,965 "administrative costs" for DEC in its Attachment B, and the $1,008,531 "M&V costs" for DEP in its Attachment B.

k. Please identify the cost items and amounts that comprise the "Other Utility Costs" of $814,718 for DEC and $507,418 for DEP given in Attachments B.

l. Please identify the cost items and amounts that comprise the "Implementation Costs" of $142,038 for DEC and $112,770 for DEP in Attachments B.

m. Please identify the cost items and amounts that comprise the "Incentives" of $25,125,423 for DEC and $19,614,360 for DEP in Attachments B.

n. Please explain the difference between "Participant Costs (gross)" and "Participant Costs (net)" on lines 12 and 13 of Attachment B. Also, what does each term represent?

Confidential Response:

[redacted]

[redacted]

[redacted]

[redacted]

Exhibit 2

Action Item 21

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
COMMISSION DIRECTIVE

ADMINISTRATIVE MATTER	☐	DATE	**January 13, 2022**
MOTOR CARRIER MATTER	☐	DOCKET NO.	**2021-143-E/2021-144-E**
UTILITIES MATTER	☑	ORDER NO.	

SUBJECT:

DOCKET NO. 2021-143-E - Application of Duke Energy Progress, LLC for Approval of Smart $aver Solar as Energy Efficiency Program;

-and-

DOCKET NO. 2021-144-E - Application of Duke Energy Carolinas, LLC for Approval of Smart $aver Solar as Energy Efficiency Program - Staff Presents for Commission Consideration Final Disposition of the Application for Approval of Smart $aver Solar as Energy Efficiency Programs, Filed on Behalf of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC.

COMMISSION ACTION:

I move the Commission approve the Smart $aver Solar programs filed by Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC). I make this motion based on my view of the evidence of record which leads me to the following conclusions:

- S.C. Code Ann. § 58-37-20 governs EE/DSM programs in South Carolina and the Smart $aver Solar program is an acceptable EE/DSM program under this statute;
- S.C. Code Ann. § 58-40-20(I) does not prohibit the Smart $aver Solar programs - that statute relates to the NEM programs and the NEM Incentive established under Act 236 and Commission Order No. 2015-194;
- Under the revised DMS/EE Mechanisms approved in Commission Order Nos. 2021-32 and 2021-33, the Utility Cost Test (UCT) is the primary cost-effectiveness test for evaluating a DSM/EE program;
- And the inputs to the UCT offered by the Duke Companies are supported by the evidence of record and are appropriate to use in evaluating the Smart $aver Solar programs.

Based on these conclusions, I move approval of the Smart $aver Solar programs.

Motion Failed.

PRESIDING: J. Williams SESSION: Regular TIME: 2:00 p.m.

	MOTION	YES	NO	OTHER	
BELSER	☑	☑	☐		Present in Hearing Room
CASTON	☐	☐	☑		Present in Hearing Room

Exhibit 2

ERVIN	☐	☐	☐	<u>Recused</u>	Recused
POWERS	☐	☐	☑		Present in Hearing Room
THOMAS	☐	☐	☑		Present in Hearing Room
C. WILLIAMS	☐	☑	☐		Present in Hearing Room
J. WILLIAMS	☐	☐	☑		Present in Hearing Room

(SEAL)

PUBLIC SERVICE COMMISSION SOUTH CAROLINA

RECORDED BY: <u>J. Schmieding</u>

Exhibit 2

Action Item 21

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
COMMISSION DIRECTIVE

ADMINISTRATIVE MATTER	☐	DATE	**January 13, 2022**
MOTOR CARRIER MATTER	☐	DOCKET NO.	**2021-143-E/2021-144-E**
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SUBJECT:

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-and-

DOCKET NO. 2021-144-E - Application of Duke Energy Carolinas, LLC for Approval of Smart $aver Solar as Energy Efficiency Program - Staff Presents for Commission Consideration Final Disposition of the Application for Approval of Smart $aver Solar as Energy Efficiency Programs, Filed on Behalf of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC.

COMMISSION ACTION:

Since the Motion to approve the program did not pass, I make a motion to disapprove the program.

PRESIDING: J. Williams SESSION: Regular TIME: 2:00 p.m.

	MOTION	YES	NO	OTHER	
BELSER	☐	☐	☑		Present in Hearing Room
CASTON	☐	☑	☐		Present in Hearing Room
ERVIN	☐	☐	☐	Recused	Recused
POWERS	☑	☑	☐		Present in Hearing Room
THOMAS	☐	☑	☐		Present in Hearing Room
C. WILLIAMS	☐	☐	☑		Present in Hearing Room
J. WILLIAMS	☐	☑	☐		Present in Hearing Room

(SEAL) RECORDED BY: J. Schmieding

Exhibit 2

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2021

H 3

HOUSE BILL 951
Committee Substitute Favorable 7/13/21
Third Edition Engrossed 7/15/21

Short Title: Modernize Energy Generation. (Public)

Sponsors:

Referred to:

May 12, 2021

A BILL TO BE ENTITLED

AN ACT TO MODERNIZE NORTH CAROLINA'S GENERATION AND GRID RESOURCES AND RATE MAKING AND TO INVEST IN CRITICAL ENERGY INFRASTRUCTURE FOR THE BENEFIT OF CUSTOMERS.

The General Assembly of North Carolina enacts:

PART I. CERTAIN REQUIREMENTS FOR GRID MODERNIZATION AND INVESTMENT IN CRITICAL ENERGY INFRASTRUCTURE

SECTION 1.(a) Findings. – The General Assembly of North Carolina finds:

(1) In order to ensure predictable and low customer electricity costs, promote economic development, protect the continued long-term reliability of electric service, and protect the environment, it is in the public interest of the State to seek to continue the transition away from coal-fired electricity generation in an orderly and disciplined manner.

(2) Overreliance on coal-fired electricity generation carries financial and operational risks in light of the future potential for limited coal supply options due to coal market consolidation, future potential coal market constraints, and coal price unpredictability. These risks are increased when combined with the effects of likely future stringent federal environmental regulations, including future potential tax or other costs, direct or indirect, imposed on coal-fired electricity generation.

(3) In transitioning away from coal-fired electricity generation, given uncertainty of long-term fuel supply and environmental regulation, it is in the public interest and the policy of the State that maintaining predictable and affordable customer electricity costs and maintaining continued long-term reliability of the electric grid are the most significant factors in determining replacement generating resources.

(4) It is in the public interest for the electric public utilities to accelerate retirement of certain coal-fired electric generating facilities in an orderly and disciplined manner that (i) ensures continued electric system reliability for all customers, (ii) mitigates the financial and operational risks associated with potential rapid coal-fired electric generating facility retirement over a short period of time in the future, (iii) seeks to maximize the overall value and lower the overall cost of such future transition, (iv) seeks to reduce the risk of future rate shock arising from the need for a more compressed transition, (v) delivers to electric

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2021

HOUSE BILL 951
Committee Substitute Favorable 7/13/21
Third Edition Engrossed 7/15/21

utility customers financial and operational benefits from diverse and new electric generation technologies, and (vi) will result in a reduction by 2030 of electric power sector CO_2 emissions of at least sixty-one percent (61%) over 2005 levels.

(5) The plan set forth herein is generally consistent with the electric public utilities' current integrated resource plan, and this act will allow the electric public utilities to implement their integrated resource plans in a more efficient manner.

(6) The plan set forth herein will provide an "all of the above" approach to replacing a limited number of coal-fired power plants with a combination of natural gas, nuclear, solar, and storage generating technologies.

(7) It is in the public interest to decrease the number of rate cases and reduce the regulatory lag that currently delays and hinders certain capital investments which would bring or maintain benefit to customers served by the electric public utilities.

(8) To facilitate the investments necessary to transition from coal-fired electricity generation in a manner that ensures predictable and affordable customer electricity costs, the General Assembly declares that it is in the public interest for the North Carolina Utilities Commission to authorize the use of performance-based regulation for electric utilities in order to achieve and encourage all of the following:

a. Alignment of electric public utilities' incentives with customer and societal interests through regulatory mechanisms that reward improved operations and increased program effectiveness.

b. Electric public utilities' innovation in service delivery to customers.

c. Electric public utilities' investments to make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system.

d. More efficient use of energy by customers by decoupling electric public utility revenues from customer consumption.

e. Multiyear rate planning to maintain predictable and affordable rates and reduce regulatory lag on necessary investments.

SECTION 1.(b) Definitions. – For purposes of Part I of this act, the following definitions shall apply:

(1) "Coal retirement and replacement plan" means a plan, as described further in subsection (d) of this section, for retiring a subcritical coal-fired electric generating facility located in North Carolina by December 31, 2030, and the replacement of such facility with a new source of energy and capacity.

(2) "Designated replacement resources" means those resources that are prescribed in subsection (c) of this section and those replacement resources that are approved by the Commission pursuant to subsection (d) of this section to replace the capacity and energy lost by the retirement of the remaining subcritical coal-fired generating facility.

(3) "Energy storage system" or "ESS" means a system, equipment, facility, or technology relating to the electric grid that (i) is capable of absorbing or receiving electrical energy, storing such energy for a period of time, and dispatching electrical energy after storage, and (ii) uses a mechanical, electrical, chemical, electrochemical, or thermal process to store such energy.

(4) "Subcritical coal-fired generating facilities" means the remaining units of the Allen Plant located in Gaston County, Marshall Units 1 and 2 located in

Catawba County, the Roxboro Plant located in Person County, Cliffside Unit 5 located in Cleveland County, and the Mayo Plant located in Person County.

SECTION 1.(c) Subcritical Coal-Fired Generating Facilities; Specific Requirements for Retirement and Associated Designated Replacement Resources. – In order to continue the transition away from coal-fired electricity generation in an orderly and disciplined manner, and to minimize the financial and operational risks to customers of overreliance on coal generation, the electric public utilities shall retire all subcritical coal-fired generating facilities by December 31, 2030, in the manner and subject to the conditions described herein.

(1) Allen Plant. – Except as provided in subdivisions (1) and (2) of subsection (e) of this section, the remaining units of the Allen Plant shall be retired on or before December 31, 2023. On or near the site of the Allen Plant, but in no event outside of Gaston County, the applicable electric public utility shall procure and own designated replacement resources comprised of one or more energy storage systems with a total capacity of approximately 20 megawatts alternating current (MW AC)/80 megawatt hours (MWh). The applicable electric public utility shall exert reasonable efforts to ensure that the designated replacement resources are constructed according to a time line that allows for retirement of the coal-fired generating facility by the targeted retirement dates, and the utility shall provide updates to the Utilities Commission regarding the status of such efforts in its integrated resource plans.

(2) Marshall Units 1 and 2. – Except as provided in subdivisions (1) and (2) of subsection (e) of this section, Marshall Units 1 and 2 shall be retired on or before December 31, 2026. On or near the site of the Marshall Plant, but in no event outside of Catawba County, the applicable electric public utility shall procure and own designated replacement resources comprised of natural gas–fueled simple-cycle combustion turbine generating facilities with a generating capacity totaling approximately 900 MW, provided that the electric public utility shall be permitted to propose a smaller combustion turbine generating facility where the electric public utility determines that technological or other constraints so require. The applicable electric public utility shall exert reasonable efforts to ensure that the designated replacement resources are constructed according to a time line that allows for retirement of the coal-fired generating facility by the targeted retirement dates, and the utility shall provide updates to the Utilities Commission regarding the status of such efforts in its integrated resource plans.

(3) Roxboro Plant. – A coal retirement and replacement plan shall be filed for the Roxboro Plant on or before September 1, 2024. With respect to the designated replacement resource for the Roxboro Plant, the replacement resource shall be a generating facility located on the Roxboro Plant site or, in the event that the applicable electric public utility, in its reasonable discretion, determines that it will be unable or infeasible to procure or construct a generating facility at the Roxboro Plant site, at another location in Person County that satisfies all of the following criteria:

a. The resource has continuous generating and dispatch capabilities and other operating characteristics that provide system reliability benefits that are equal to or greater than the retiring Roxboro Plant.

b. The resource provides effective load carrying capability sufficient to ensure continued reliability of the system.

c. The resource has the ability to deliver continuous power at or near the maximum capacity of the resource for a continuous period of one week or longer without reliance on other grid resources.

(4) Cliffside Unit 5. – A coal retirement and replacement plan shall be filed for Cliffside Unit 5 on or before September 1, 2027. With respect to designated replacement resources for the facility, the replacement resource shall be an energy storage system to be procured and owned by the applicable electric public utility. The applicable electric public utility shall seek to locate a substantial portion of the ESS on the Cliffside Unit 5 site, but shall be permitted to site such ESS on or near other electric public utility property where such siting will provide increased benefit to customers.

(5) Mayo Plant. – A coal retirement and replacement plan shall be filed for the Mayo Plant on or before September 1, 2027. With respect to designated replacement resources for these facilities, the replacement resource for each facility shall be an ESS to be procured and owned by the applicable electric public utility. The applicable electric public utility shall seek to locate a substantial portion of the ESS on the site of the applicable subcritical coal-fired generating facility but shall be permitted to site such ESS on or near other electric public utility property where such siting will provide increased benefit to customers.

SECTION 1.(d) Coal Retirement and Replacement Plans Generally. –

(1) A coal retirement and replacement plan shall include all of the following:

a. The proposed retirement date for the applicable subcritical coal-fired generating facility and the reasons for that proposed retirement date.

b. The proposed type, size, and location of the replacement resource or resources intended to replace the energy and capacity of the subcritical coal-fired generating facility in order to ensure safe, reliable, and cost-effective service to the electric public utility's customers and the projected timing of the commercial operation of such replacement resource or resources.

c. A forecast of capital costs, fuel costs, other operation and maintenance costs, and the capacity factors of the proposed replacement resource, as well as any assumptions about future regulatory compliance costs.

d. In the case of replacement resources that would require a certificate under G.S. 62-110.1 or otherwise, to the extent not already required above, the information that would be required in connection with an application for certificate of a generating facility under G.S. 62-110.1, except that the information required under or in connection with G.S. 62-110.1(d) shall not be required.

(2) After receipt of a coal retirement and replacement plan, the Commission shall do all of the following:

a. Establish a procedural schedule to allow interested parties to intervene in the proceeding, to facilitate discovery of evidence between and among parties to the proceeding, and to receive comments of the parties and the filing of any direct or rebuttal expert witness testimony.

b. Hold one or more public hearings and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in the county in which the subcritical coal-fired generating facility is located.

c. Schedule an evidentiary hearing to allow for the cross-examination of expert witnesses, to resolve all contested issues between the parties to the proceeding, and to address any questions or issues the Commission may raise upon its own motion.

(3) After completion of the process described in subdivision (2) of this subsection, the Commission shall issue an order approving, modifying, or rejecting an electric public utility's coal retirement and replacement plan within 180 days after the filing thereof. The Commission shall approve a coal retirement and replacement plan if it finds all of the following:

a. The coal retirement and replacement plan complies with the applicable requirements set forth in this subsection.

b. The replacement resource proposed in a coal retirement and replacement plan is sized appropriately to (i) ensure sufficient energy on an hourly basis over an annual period and ensure sufficient capacity to serve anticipated peak electrical load plus an adequate planning reserve margin based upon the applicable electric public utility's then current projections of customer load requirements and (ii) provide equivalent ancillary services and ensure compliance with any applicable reliability standards, including the North American Electric Reliability Corporation's (NERC) reliability standards.

c. The electric public utility has reasonably and prudently utilized competitive equipment procurement practices to ensure that the projected cost of the proposed replacement resource is reasonable in accordance with the requirements set forth in subdivisions (3) through (5) of subsection (c) of this section

(4) In a decision issued pursuant to subdivision (3) of this subsection approving any replacement resource, the Commission shall include an approved construction cost for each such replacement resource. If a replacement resource requires a certificate of public convenience and necessity under G.S. 62-110.1 or otherwise, and is approved by the Commission under this section, such replacement resource shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1, and the Commission shall issue a certificate of public convenience and necessity for such replacement resources at the time of its approval, and no further process shall be required under G.S. 62-110.1 except as otherwise addressed herein.

SECTION 1.(e) General Provisions Applicable to Retirement of Subcritical Coal-Fired Generating Facilities. –

(1) Notwithstanding any date established under subsection (c) or (d) of this section that requires retirement of a subcritical coal-fired generating facility, in the event the applicable electric public utility determines that the retirement of any such facility would have the potential to compromise reliability of the electric public utility's service, or otherwise impact the ability of the electric public utility to comply with any applicable reliability requirements, the electric public utility shall file notice with the Commission describing the reliability issues preventing compliance with the requirement for retirement by the date specified and requesting a delay of retirement date. Upon receipt of a notice and request for retirement delay as authorized by this subdivision, the Commission may conduct a hearing regarding such delay and shall issue an order approving or rejecting the request for delay within 90 days of receipt of such notice and request.

(2) In order to ensure the continued reliability of the electric system, no subcritical coal-fired generating facilities shall be retired unless and until the applicable

designated replacement resource has been placed in-service; provided, however, that the electric public utility shall be authorized to retire the subcritical coal-fired generating facility prior to the in-service date of the applicable designated replacement resource if the electric public utility determines that it will be able to maintain reliable service in that circumstance.

(3) In the case of each subcritical coal-fired generating facility that is retired pursuant to this section, the applicable electric public utility shall be permitted to establish a regulatory asset for the remaining net book value of each subcritical coal-fired generating facility and amortize the regulatory asset at the same rate the subcritical coal-fired generating facility was previously being depreciated. The regulatory asset shall be included in rate base for rate-making purposes, and in a future general rate proceeding the Commission shall establish an amortization period for recovery and allow a return on the unamortized balance at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

SECTION 1.(f) General Provisions Applicable to Designated Replacement Resources Purchased and Owned by the Electric Public Utilities Pursuant to Subsection (c) of this Section. –

(1) In order to ensure predictable and affordable customer electricity costs for all customers and to ensure an orderly and disciplined transition, the applicable electric utility shall:

a. In the case of the nonrenewable generating facilities procured pursuant to subsection (c) of this section, utilize competitive procurement for the design, engineering, and construction of such generating facilities.

b. In the case of any renewable energy facilities procured pursuant to subsection (c) of this section, competitively procure and purchase such facilities from third parties utilizing the procedures set forth and in compliance with the requirements of G.S. 62-110.8 for procurements occurring after January 1, 2022; provided, however, that (i) the procuring electric public utility shall own and operate all of the renewable energy facilities procured pursuant to this section and the percentage allocation of ownership between third parties and the electric public utilities for procurements commencing after January 1, 2021, that is specified in subsection (b1) of G.S. 62-110.8 for renewable generating facilities shall not apply to procurements of renewable energy facilities pursuant to subsection (c) of this section and (ii) the cost cap specified in subsection (g1) of G.S. 62-110.8 shall not apply to the procurement of renewable energy facilities pursuant to subsection (c) of this section.

c. In the case of the ESS procured pursuant to subsection (c) of this section, competitively procure and purchase such facilities from third parties utilizing the procurement procedures and requirements for independent oversight set forth in G.S. 62-110.8 for procurements occurring after January 1, 2022; provided, however, that (i) the procuring electric public utility shall own and operate all of the ESS procured pursuant to this section and the percentage allocation of ownership between third parties and the electric public utilities for procurements commencing after January 1, 2021, that is specified in subsection (b1) of G.S. 62-110.8 for renewable generating facilities shall not apply to procurements of ESS pursuant to subsection (c) of this section and (ii) the cost cap specified in subsection (g1) of

G.S. 62-110.8 shall not apply to the procurement of ESS pursuant to subsection (c) of this section.

(2) The designated replacement resources identified in subsection (c) of this section that require a certificate of public convenience and necessity under G.S. 62-110.1, or otherwise, shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1 so long as the applicable electric public utility reasonably and prudently procures such replacement generation in a manner consistent with subdivision (1) of this subsection.

(3) Notwithstanding G.S. 62-110.1, the Commission shall provide an expedited decision on an application for a certificate of public convenience for all such resources. The Commission shall render its decision on an application for a certificate, including any related transmission line needed for the new generation facility, within 90 days of the date the application is filed. An application for a certificate of public convenience and necessity to construct or procure those designated replacement resources identified in subsection (c) of this section that require a certificate of public convenience and necessity and the renewable generating facilities purchased and owned by the electric public utilities pursuant to G.S. 62-110.8 through procurements occurring after January 1, 2021, shall be subject to all of the following:

a. The applicable electric public utility shall provide written notice to the Commission of the date the electric public utility intends to file an application no less than 30 days prior to the submission of the application.

b. When the electric public utility applies for a certificate as provided in this subdivision, it shall submit to the Commission an estimate of the costs of construction of the generating facility in such detail as the Commission may require.

c. G.S. 62-110.1(d) and (e) and G.S. 62-82(a) shall not apply to such applications.

d. The Commission shall hold a single public hearing for such applications and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in the county in which the generating facility is located.

(4) The electric public utilities shall be permitted to recover from its customers the reasonably and prudently incurred cost of all generation facilities and energy storage systems purchased or constructed pursuant to subsection (c) or (d) of this section. In the case of an energy storage system approved by the Commission pursuant to subsection (d) of this section, there shall be a rebuttable presumption that the electric public utility's actual costs are reasonable and prudent if such actual costs are at or below the projected costs approved by the Commission. In the case of a certificated generation facility approved by the Commission pursuant to this subsection or subsection (d) of this section or procured pursuant to G.S. 62-110.8, notwithstanding G.S. 62-110.1(f1), there shall be a rebuttable presumption that the electric public utility's actual costs are reasonable and prudent if such actual costs are at or below the projected costs approved by the Commission, provided that upon the request of the electric public utility or upon its own motion pursuant to G.S. 62-110.1(f), the Commission may conduct an ongoing review of construction of the facility under G.S. 62-110.1(f), in which case the cost recovery provisions of G.S. 62-110.1(f1) shall apply except that the electric

public utility may seek cost recovery in a rate case under either G.S. 62-133 or G.S. 62-133.16. The electric public utilities shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all such costs incurred pursuant to this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include, but are not limited to, operation and maintenance expenses, administration costs, property tax, depreciation expenses, income taxes, carrying costs related to electric plant investments, and regulatory assets at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

SECTION 1.(g) G.S. 62-110.8 reads as rewritten:

"**§ 62-110.8. Competitive procurement of renewable energy.**

(a) Each electric public utility shall file for Commission approval a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs. Renewable energy facilities eligible to participate in the competitive procurement shall include those facilities that use renewable energy resources identified in G.S. 62-133.8(a)(8) ~~but~~ but, except as provided in subsection (b1) of this section, shall be limited to facilities with a nameplate capacity rating of 80 megawatts ~~(MW)~~ alternating current (MW AC) or less that are placed in service after the date of the electric public utility's initial competitive procurement. Subject to the limitations set forth in subsections (b) and (c) of this section, the electric public utilities shall issue requests for proposals to procure and shall procure, energy and capacity from renewable energy facilities in the aggregate amount of ~~2,660 megawatts (MW), and the total amount shall be reasonably allocated over a term of 45 months beginning when the Commission approves the program.~~ 7,327 megawatts alternating current (MW AC), and the total amount shall be reasonably allocated over a term of 106 months beginning when the Commission approves the program; provided, however, that the electric public utilities shall conduct an annual procurement of approximately 777 megawatts alternating current (MW AC) each calendar year beginning in 2021 and concluding in 2026. The electric public utilities shall be permitted to petition the Commission for approval to modify the procurement schedule established herein in the event that administration of annual procurements becomes impractical due to the need to align with then existing interconnection study processes or other factors beyond the utilities' control, and the Commission shall approve such modifications if it determines that the modifications would be in the public interest. The Commission shall require the additional competitive procurement of renewable energy capacity by the electric public utilities in an amount that includes all of the following: (i) any unawarded portion of the initial competitive procurement required by this subsection; (ii) any deficit in renewable energy capacity identified pursuant to subdivision (1) of subsection ~~(b)~~ (b2) of this section; and (iii) any capacity reallocated pursuant to G.S. 62-159.2. In addition, at the termination of the initial competitive procurement period of ~~45 months, the offering of a new renewable energy resources competitive procurement and the amount to be procured shall be determined by the Commission, based on a showing of need evidenced by the electric public utility's most recent biennial integrated resource plan or annual update approved by the Commission pursuant to G.S. 62-110.1(c).~~ 106 months, the Commission shall determine whether it is in the interest of ratepayers to require further competitive procurement of renewable generating facilities by the electric public utilities under this subsection, and shall also determine the amount to be procured beyond that required by this subsection, and the allocation of ownership between third parties and electric public utilities. The Commission's determination shall be based on the electric public utility's most recent biennial integrated resource plan or annual update accepted or approved by the Commission, provided that such plan assures adequate, reliable utility service.

(b) Electric public utilities may jointly or individually implement the aggregate competitive procurement requirements set forth in subsection (a) of this section ~~and~~ and, with respect to procurements commencing prior to January 1, 2021, may satisfy such requirements for the procurement of renewable energy capacity to be supplied by renewable energy facilities through any of the following: (i) renewable energy facilities to be acquired from third parties and subsequently owned and operated by the soliciting public utility or utilities; (ii) renewable energy facilities to be constructed, owned, and operated by the soliciting public utility or utilities subject to the limitations of subdivision (4) of this subsection; or (iii) the purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the procuring public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources.

(b1) All procurements required by subsection (a) of this section commencing after January 1, 2021, and continuing through December 31, 2026, shall be subject to the following requirements:

(1) Forty-five percent (45%) of the total megawatts alternating current (MW AC) of renewable energy facilities scheduled to be procured in procurements commencing after January 1, 2021, shall be supplied through the execution of power purchase agreements with third parties pursuant to which the electric public utility purchases of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources.

(2) Fifty-five percent (55%) of the total megawatts alternating current (MW AC) of renewable energy facilities scheduled to be procured through procurements commencing after January 1, 2021, shall be supplied from renewable energy facilities purchased from third parties and owned and operated by the soliciting electric public utility. The cap on facility nameplate capacity of 80 megawatts alternating current (MW AC) or less established by subsection (a) of this section shall not apply to facilities procured pursuant to this subdivision.

(b2) Procured renewable energy capacity, as provided for in this section, shall be subject to the following limitations:

(1) ~~If prior to the end of the initial 45-month competitive procurement period the public utilities subject to this section have executed power purchase agreements and interconnection agreements for renewable energy capacity within their balancing authority areas that are not subject to economic dispatch or curtailment and were not procured pursuant to G.S. 62-159.2 having an aggregate capacity in excess of 3,500 megawatts (MW), the Commission shall reduce the competitive procurement aggregate amount by the amount of such exceedance. If the aggregate capacity of such renewable energy facilities is less than 3,500 megawatts (MW) at the end of the initial 45-month competitive procurement period, the Commission shall require the electric public utilities to conduct an additional competitive procurement in the amount of such deficit.~~In the event that it is reasonably projected that, on or before January 1, 2027, the electric public utilities subject to the procurement obligation under subsection (a) of this section will have executed power purchase agreements and interconnection agreements with renewable generating facilities within their balancing authority areas having an aggregate megawatts alternating current (MW AC) capacity in excess of 3,500 megawatts alternating current

(MW AC), exclusive of power purchase agreements entered into pursuant to this section, G.S. 62-159.2, and G.S. 62-126.8B, the Commission shall reduce the total aggregate megawatts alternating current (MW and AC) capacity of renewable generating facilities required for procurement under this section by an amount equal to the difference between (i) the amount of aggregate megawatts alternating current (MW AC) capacity of renewable generating facilities with executed power purchase agreements and interconnection agreements, including all such renewable generating facilities located in the electric public utility's balancing authority area, whether located inside or outside the geographic boundaries of the State but exclusive of power purchase agreements entered into pursuant to this section, G.S. 62-159.2, and G.S. 62-126.8B and (ii) 3,500 megawatts alternating current (MW AC).

(2) To ensure the cost-effectiveness of ~~procured~~ new renewable energy resources, ~~each public utility's procurement obligation~~ the price to be paid under any power purchase agreements for third-party owned resources, combined with the cost of any necessary transmission or distribution upgrade, shall be capped by the public utility's current forecast of its avoided cost calculated over the term of the power purchase agreement. The public utility's current forecast of its avoided cost shall be consistent with the Commission-approved avoided cost methodology.

(3) Each public utility shall submit to the Commission for approval and make publicly available at 30 days prior to each competitive procurement solicitation a pro forma ~~contract~~ power purchase agreement to be utilized for the purpose of informing market participants of terms and conditions of the competitive procurement. Each pro forma ~~contract~~ power purchase agreement shall define limits and compensation for resource dispatch and ~~curtailments.~~ curtailments; provided, however, that curtailment shall be limited to a percentage of the expected output of the generation facility that is determined by the Commission to be in the public interest. The pro forma ~~contract~~ power purchase agreement shall be for a term of 20 years; provided, however, the Commission may approve a contract term of a different duration if the Commission determines that it is in the public interest to do so.

(4) ~~No~~ With respect only to those procurements commencing prior to January 1, 2021, more than thirty percent (30%) of an electric public utility's competitive procurement requirement may be satisfied through the utility's own development of renewable energy facilities offered by the electric public utility or any subsidiary of the electric public utility that is located within the electric public utility's service territory. This limitation shall not apply to any renewable energy facilities acquired by an electric public utility that are selected through the competitive procurement and are located within the electric public utility's service territory.

(c) Subject to the aggregate competitive procurement requirements established by this section, the electric public utilities shall have the authority to determine the location and allocated amount of the competitive procurement within their respective balancing authority areas, whether located inside or outside the geographic boundaries of the State, taking into consideration (i) the State's desire to foster diversification of siting of renewable energy resources throughout the State; (ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and (iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as nondispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs. In the case of renewable energy facilities to be procured and owned by the electric public utilities pursuant to this section, the electric public utilities shall be permitted through the competitive processes described herein to solicit bids for the construction of such renewable energy facilities on or near property owned or controlled by the electric public utility, including the site of any retiring subcritical coal-fired generating facility, where such sites will provide benefits to customers, including through reduced interconnection or infrastructure costs.

(d) ~~The~~ For all procurements commencing prior to January 1, 2022, the competitive procurement of renewable energy capacity established pursuant to this section shall be independently administered by a third-party entity to be approved by the ~~Commission. The third-party entity shall~~ Commission, provided that in the case of any procurement commencing after January 1, 2021, but prior to January 1, 2022, the electric public utilities shall be permitted to directly assist the third-party entity and provide input on all aspects of the procurement and shall collaborate with the third-party entity to develop and publish the methodology used to evaluate responses received pursuant to a competitive procurement solicitation and to ensure that all responses are treated equitably. For all procurements commencing after January 1, 2022, the competitive procurement of renewable energy capacity required pursuant to this section shall be administered by the electric public utilities in accordance with the rules to be adopted pursuant to subdivision (1) of subsection (h) of this section, and subject to oversight and evaluation by a third-party entity to be approved by the Commission. All reasonable and prudent administrative and related expenses incurred to implement this subsection shall be recovered from market participants through administrative fees levied upon those that participate in the competitive bidding process, as approved by the Commission.

(e) ~~An~~ With respect only to those procurements commencing prior to January 1, 2021, an electric public utility may participate in any competitive procurement process, but shall only participate within its own assigned service territory. If the public utility uses nonpublicly available information concerning its own distribution or transmission system in preparing a proposal to a competitive procurement, the public utility shall make such information available to third parties that have notified the public utility of their intention to submit a proposal to the same request for proposals.

(e1) In the case of all procurements commencing after January 1, 2021, neither the electric public utilities nor any of their affiliates shall be permitted to submit bids into the competitive procurement process or to have any financial interest in third-party bidders.

(e2) The renewable generating facilities purchased and owned by the electric public utilities pursuant to this section through procurements occurring after January 1, 2021, shall be deemed consistent with the public convenience and necessity and public interest for purposes of G.S. 62-110.1 so long as the renewable generating facilities were procured in compliance with the procurement process established under this section.

(f) For purposes of this section, the term "balancing authority" means the entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time, and the term "balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of the balancing authority, and the balancing authority maintains load-resource balance within this area.

(g) An electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets ~~that are~~ procured pursuant to this section prior to January 1, 2021, through an annual rider approved by the Commission and reviewed annually. Provided it is in the public interest, the authorized revenue for any such renewable energy facilities owned by an electric public utility and procured pursuant to this section prior to January 1, 2021, may be calculated on a market basis in lieu of cost-of-service based recovery, using data from the applicable competitive procurement to determine the market price in accordance with the methodology established by the Commission pursuant to subsection (h) of this section. The annual increase in the aggregate amount of these costs that are recoverable by an electric public utility pursuant to this subsection shall not exceed one percent (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year.

(g1) With respect to all procurements commencing after January 1, 2021, an electric public utility shall be permitted to recover from its customers the reasonably and prudently incurred costs paid under power purchase agreements executed pursuant to this section through the rider authorized under subsection (g) of this section; provided, however, costs that may be recovered by the utility for utility-owned renewable generating facilities shall be subject to the same cost caps established under subdivision (2) of subsection (b2) of this section applicable to power purchases of third-party owned resources. An electric public utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all such costs incurred pursuant to this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include, but are not limited to, operation and maintenance expenses, administration costs, property tax, depreciation expense, income taxes, carrying costs related to electric plant investments, and regulatory assets at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

(g2) In determining the most cost-effective proposals in any procurement process under this section, the electric public utility shall take into account the cost of any needed transmission or distribution upgrades but, in the case of any proposals selected by the electric public utility, such transmission or distribution upgrades costs shall not be directly assigned to the bidder but instead shall be included in the electric public utility's rate base for rate-making purposes. In addition, the electric public utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental cost of all such upgrades, along with associated carrying costs based on the electric public utility's then authorized net-of-tax, weighted average cost of capital, until such time as the costs can be reflected in customer rates. In a future general rate proceeding, the Commission shall establish an amortization period for recovery and allow a return on the unamortized balance at the electric public utility's then authorized, net-of-tax, weighted average cost of capital.

(h) The Commission shall adopt rules to implement the requirements of this section, as follows:

(1) Oversight of the competitive procurement ~~program.~~program by the Commission and by independent third parties. No later than May 1, 2022, the Commission's rules shall be amended to provide for (i) administration of the procurement process, including establishing the selection methodology and selection of projects, by the electric public utilities subject to the oversight of an independent evaluator retained by the utilities pursuant to a contract approved by the Commission, (ii) approval by the Commission of the electric public utilities' selection methodology and the independent evaluator's review procedures, (iii) detailed reports by the independent evaluator to the Commission regarding the results of each procurement, and (iv) any further changes related to the foregoing, including modification of communication restrictions deemed appropriate by the Commission.

(2) To provide for a waiver of regulatory conditions or code of conduct requirements that would unreasonably restrict a public utility or its affiliates from participating in the competitive procurement ~~process,~~ with respect to procurements occurring under this section prior to January 1, 2021, unless the

Commission finds that such a waiver would not hold the public utility's customers harmless.

(3) Establishment of a procedure for expedited review and approval of certificates of public convenience and necessity, or the transfer thereof, for renewable energy facilities owned by the public utility and procured pursuant to this section. The Commission shall issue an order not later than 30 days after a petition for a certificate is filed by the public utility.

(4) Establishment of a methodology to allow an electric public utility to recover its costs pursuant to ~~subsection (g)~~ subsections (g), (g1), and (g2) of this section.

(5) Establishment of a procedure for the Commission to modify or delay implementation of the provisions of this section in whole or in part if the Commission determines that it is in the public interest to do so.

…."

SECTION 1.(h) The requirements of subsections (a) through (g) of this section shall not apply to an electric public utility serving fewer than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021.

SECTION 1.(i) G.S. 62-133.2 reads as rewritten:

"**§ 62-133.2. Fuel and fuel-related charge adjustments for electric utilities.**

…

(d) The Commission shall provide for notice of a public hearing with reasonable and adequate time for investigation and for all intervenors to prepare for hearing. At the hearing the Commission shall receive evidence from the utility, the Public Staff, and any intervenor desiring to submit evidence, and from the public generally. In reaching its decision, the Commission shall consider all evidence required under subsection (c) of this section as well as any and all other competent evidence that may assist the Commission in reaching its decision including changes in the cost of fuel consumed and fuel-related costs that occur within a reasonable time, as determined by the Commission, after the test period is closed. The Commission shall incorporate in its cost of fuel and fuel-related costs determination under this subsection the experienced over-recovery or under-recovery of reasonable costs of fuel and fuel-related costs prudently incurred during the test period, based upon the prudent standards set pursuant to subsection (d1) of this section, in fixing an increment or decrement rider. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of costs of fuel and fuel-related costs through the date that is 30 calendar days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual hearing pursuant to this section. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case. The burden of proof as to the correctness and reasonableness of the charge and as to whether the cost of fuel and fuel-related costs were reasonably and prudently incurred shall be on the utility. The Commission shall allow only that portion, if any, of a requested cost of fuel and fuel-related costs adjustment that is based on adjusted and reasonable cost of fuel and fuel-related costs prudently incurred under efficient management and economic operations. Efficient management and economic operations include actions and decisions that modify commitment and dispatch to manage seasonal demand, mitigate fuel supply security and transportation risk, and maintain dispatchable capacity value. In evaluating whether cost of fuel and fuel-related costs were reasonable and prudently incurred, the Commission shall apply the rule adopted pursuant to subsection (d1) of this section. To the extent that the Commission determines that an increment or decrement to the rates of the utility due to changes in the cost of fuel and fuel-related costs over or under base fuel costs established in the preceding general rate case is just and reasonable, the Commission shall order that the increment or decrement become effective for all sales of electricity and remain in effect until changed in a subsequent general rate case or annual proceeding under this section.

…."

SECTION 1.(j) This section is effective when it becomes law.

AUTHORIZE FINANCING OF CERTAIN ENERGY TRANSITION COSTS

SECTION 2.(a) Article 8 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-173. Financing for certain energy transition costs.**

(a) Definitions. – The following definitions apply in this section:

(1) Ancillary agreement. – A bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with energy transition bonds.

(2) Assignee. – A legally recognized entity to which a public utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to energy transition property. The term includes a corporation, limited liability company, general partnership or limited partnership, public authority, trust, financing entity, or any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to energy transition property.

(3) Bondholder. – A person who holds an energy transition bond.

(4) Code. – The Uniform Commercial Code, Chapter 25 of the General Statutes.

(5) Commission. – The North Carolina Utilities Commission.

(6) Energy transition bonds. – Bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued by a public utility or an assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved energy transition costs and financing costs, and that are secured by or payable from energy transition property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

(7) Energy transition charge. – The amounts authorized by the Commission to repay, finance, or refinance energy transition costs and financing costs and that are nonbypassable charges (i) imposed on and part of all retail customer bills, (ii) collected by a public utility or its successors or assignees, or a collection agent, in full, separate and apart from the public utility's base rates, and (iii) paid by all existing or future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this State.

(8) Energy transition costs. – A cost other than a monetary penalty, fine, or forfeiture assessed against a public utility by a government agency or court under a federal or State environmental statute, rule, or regulation for retirement of Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant. The total amount that shall be securitized as provided by this subdivision shall be five hundred million dollars ($500,000,000), which shall be allocated among these plants in a

manner that realizes the greatest cost savings to ratepayers as determined by the Commission. Such costs include:

a. An amount determined and approved by the Commission not to exceed the total aggregate unrecovered net book value, plus the costs set forth in sub-subdivisions b., c., and d. of this subdivision, of the subcritical coal-fired electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant.

b. The following costs the public utility has incurred or will incur caused by, associated with, or that remain as a result of the early retirement of electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant:

1. All incremental costs, including capital costs, appropriate for recovery from existing and future retail customers receiving transmission or distribution service from the electric public utility that the utility has incurred or expects to incur as a result of the early retirement of the Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant, including the costs of decommissioning and restoring the site of such early retired electric generating facilities, except for costs incurred pursuant to G.S. 130A-309.200 through G.S. 130A-309.226 or 40 C.F.R. Subpart D, which are not subject to this section.

2. The electric public utility's cost of capital from the date this section becomes effective to the date the energy transition bonds are issued, calculated using the public utility's weighted average cost of capital as defined in its most recent base rate case proceeding before the Commission net of applicable income tax savings related to the interest component. Such costs also include other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

c. Energy transition costs shall be net of applicable insurance proceeds, tax benefits, and any other amounts intended to reimburse the public utility for energy transition activities such as government grants, or aid of any kind and where determined appropriate by the Commission, and may include adjustments for capital replacement and operating costs previously considered in determining normal amounts in the public utility's most recent general rate case proceeding.

d. With respect to energy transition costs that the public utility expects to incur, any difference between costs expected to be incurred and actual, reasonable, and prudent costs incurred, or any other rate-making adjustments appropriate to fairly and reasonably assign or allocate energy transition cost recovery to customers over time, shall be addressed in a future general rate proceeding, as may be facilitated by other orders of the Commission issued at the time or prior to such proceeding; provided, however, that the Commission's adoption of a financing order and approval of the issuance of energy transition bonds may not be revoked or otherwise modified.

(9) Energy transition property. – All of the following:

a. All rights and interests of a public utility or successor or assignee of the public utility under a financing order, including the right to impose, bill, charge, collect, and receive energy transition charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order.

b. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

(10) Financing costs. – The term includes all of the following:

a. Interest and acquisition, defeasance, or redemption premiums payable on energy transition bonds.

b. Redemption premiums or make-whole payments related to the early redemption of the public utility's first mortgage bonds or other debt associated with the retired electric generating facility.

c. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to energy transition bonds.

d. Any other cost related to issuing, supporting, repaying, refunding, and servicing energy transition bonds, including servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of energy transition bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order.

e. Any taxes and license fees or other fees imposed on the revenues generated from the collection of the energy transition charge or otherwise resulting from the collection of energy transition charges, in any such case whether paid, payable, or accrued.

f. Any State and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued.

g. Any costs incurred by the Commission or public staff for any outside consultants or counsel retained in connection with the securitization of energy transition costs.

(11) Financing order. – An order that authorizes the issuance of energy transition bonds; the imposition, collection, and periodic adjustments of an energy transition charge; the creation of energy transition property; and the sale, assignment, or transfer of energy transition property to an assignee.

(12) Financing party. – Bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

(13) Financing statement. – Defined in Article 9 of the Code.

(14) Pledgee. – A financing party to which a public utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to energy transition property.

(15) Public utility. – A public utility, as defined in G.S. 62-3, that sells electric power to retail electric customers in the State.

(b) Financing Orders. –

(1) A public utility shall petition the Commission for a financing order for energy transition costs. The petition shall include all of the following:

a. The energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed.

b. An estimate of the financing costs related to the energy transition bonds.

c. An estimate of the energy transition charges necessary to recover the energy transition costs and financing costs and the proposed period for recovery of such costs.

d. A comparison between the net present value of the costs to customers that are estimated to result from the issuance of energy transition bonds and the costs that would result from the application of the traditional method of financing and recovering energy transition costs from customers. The comparison shall demonstrate that the issuance of energy transition bonds and the imposition of energy transition charges are expected to provide quantifiable benefits to customers.

e. Direct testimony and exhibits supporting the petition.

(2) If a public utility is subject to a settlement agreement that governs the type and amount of principal costs that could be included in energy transition costs, and the principal costs are not already subject to review and approval by the Commission in a separate proceeding, then the public utility shall file a petition with the Commission for review and approval of those principal costs no later than 90 days before filing a petition for a financing order pursuant to this section.

(3) Petition and order. –

a. Proceedings on a petition submitted pursuant to this subdivision begin with the petition by a public utility, initially filed on or before January 1, 2023, subject to the time frame specified in subdivision (2) of this subsection, if applicable, and shall be disposed of in accordance with the requirements of this Chapter and the rules of the Commission, except as follows:

1. Within 14 days after the date the petition is filed, the Commission shall establish a procedural schedule that permits a Commission decision no later than 135 days after the date the petition is filed.

2. No later than 135 days after the date the petition is filed, the Commission shall issue a financing order or an order rejecting the petition. If a petition for a financing order is rejected, the Commission shall include in its order the reasons for the rejection, and the utility shall resubmit a petition within 60 days of the order rejecting the earlier petition. A party to the

Commission proceeding may petition the Commission for reconsideration of the financing order within five days after the date of its issuance.

b. A financing order issued by the Commission to a public utility shall include all of the following elements:

1. Except for changes made pursuant to the formula-based mechanism authorized under this section, the amount of energy transition costs to be financed using energy transition bonds. The Commission shall describe and estimate the amount of financing costs that shall be recovered through energy transition charges and specify the period over which energy transition costs and financing costs shall be recovered.
2. A finding that the proposed issuance of energy transition bonds and the imposition and collection of an energy transition charge are expected to provide quantifiable benefits to customers as compared to the cost that would have been incurred absent the issuance of energy transition bonds.
3. A finding that the structuring and pricing of the energy transition bonds are reasonably expected to result in the lowest energy transition charges consistent with market conditions at the time the energy transition bonds are priced and the terms set forth in such financing order.
4. A requirement that, for so long as the energy transition bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of energy transition charges authorized under a financing order shall be nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in this State.
5. A formula-based true-up mechanism for making, at least annually, expeditious periodic adjustments in the energy transition charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of energy transition bonds and financing costs and other required amounts and charges payable in connection with the energy transition bonds.
6. The energy transition property that is, or shall be, created in favor of a public utility or its successors or assignees and that shall be used to pay or secure energy transition bonds and all financing costs.
7. The degree of flexibility to be afforded to the public utility in establishing the terms and conditions of the energy transition bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs.

8. How energy transition charges will be allocated among customer classes.

9. A requirement that, after the final terms of an issuance of energy transition bonds have been established and before the issuance of energy transition bonds, the public utility determines the resulting initial energy transition charge in accordance with the financing order and that such initial energy transition charge be final and effective upon the issuance of such energy transition bonds without further Commission action so long as the energy transition charge is consistent with the financing order.

10. A requirement that the public utility, simultaneously with the inception of the collection of energy transition charges, reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement in customer rates associated with the utility assets being financed by energy transition bonds. The public utility shall propose the method to reduce its rates in accordance with this sub-sub-subdivision in its petition.

11. A method of tracing funds collected as energy transition charges, or other proceeds of energy transition property, and determine that such method shall be deemed the method of tracing such funds and determining the identifiable cash proceeds of any energy transition property subject to a financing order under applicable law.

12. Establishment of a bond team consisting of representatives of the public utility and its consultant, the Public Staff and its consultant, and the Commission with a designated Commissioner and the Commission's consultant and counsel.

13. A direction for the bond team to work together and make all decisions as to the structuring, marketing, and pricing of the energy transition bonds; the selection of the underwriters; and the approval of the transaction documents. The Commission shall have final decision-making authority on all matters considered by the bond team.

14. Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to a public utility may provide that creation of the public utility's energy transition property is conditioned upon, and simultaneous with, the sale or other transfer of the energy transition property to an assignee and the pledge of the energy transition property to secure energy transition bonds.

d. If the Commission issues a financing order, the public utility shall file with the Commission at least annually a petition or a letter applying the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of energy transition charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of energy transition bonds approved under the financing order. Within 30 days after receiving a public utility's request pursuant to this paragraph, the Commission shall either approve the request or inform the public utility of any mathematical or clerical errors in its calculation. If the Commission informs the utility of mathematical or clerical errors in its calculation, the utility may correct its error and refile its request. The time frames previously described in this paragraph shall apply to a refiled request.

e. Subsequent to the transfer of energy transition property to an assignee or the issuance of energy transition bonds authorized thereby, whichever is earlier, a financing order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust energy transition charges approved in the financing order. After the issuance of a financing order, the public utility retains sole discretion regarding whether to assign, sell, or otherwise transfer energy transition property.

(4) At the request of a public utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding the energy transition bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded energy transition bonds and the issuance of new energy transition bonds, the Commission shall adjust the related energy transition charges accordingly.

(5) Within 60 days after the Commission issues a financing order or a decision denying a request for reconsideration or, if the request for reconsideration is granted, within 30 days after the Commission issues its decision on reconsideration, an adversely affected party may petition for judicial review in the Supreme Court of North Carolina. Review on appeal shall be based solely on the record before the Commission and briefs to the court and is limited to determining whether the financing order, or the order on reconsideration, conforms to the State Constitution and State and federal law and is within the authority of the Commission under this section.

(6) Duration of financing order. –

a. A financing order remains in effect and energy transition property under the financing order continues to exist until energy transition bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such energy transition bonds have been recovered in full.

b. A financing order issued to a public utility remains in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the public utility or its successors or assignees.

(c) Exception to Commission Jurisdiction. – The Commission may not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this Chapter, consider the energy transition bonds issued pursuant to a financing order to be the debt of the public utility other than for federal income tax purposes, consider the energy transition charges paid under the financing order to be the revenue of the public utility for any purpose, or consider the energy transition costs or financing costs specified in the financing order to be the costs of the public utility, nor may the Commission determine any action taken by a public utility which is consistent with the financing order to be unjust or unreasonable.

(d) Public Utility Duties. – The electric bills of a public utility that has obtained a financing order and caused energy transition bonds to be issued must comply with the provisions of this subsection; however, the failure of a public utility to comply with this subsection does not invalidate, impair, or affect any financing order, energy transition property, energy transition charge, or energy transition bonds. The public utility must do all of the following:

(1) Explicitly reflect that a portion of the charges on such bill represents energy transition charges approved in a financing order issued to the public utility and, if the energy transition property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to energy transition charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the energy transition charge and the ownership of the charge.

(2) Include the energy transition charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill.

(e) Energy Transition Property. –

(1) Provisions applicable to energy transition property. –

a. All energy transition property that is specified in a financing order constitutes an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of energy transition charges depends on the public utility, to which the financing order is issued, performing its servicing functions relating to the collection of energy transition charges and on future electricity consumption. The property exists (i) regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to customers by the public utility or its successors or assignees and the future consumption of electricity by customers.

b. Energy transition property specified in a financing order exists until energy transition bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such energy transition bonds have been recovered in full.

c. All or any portion of energy transition property specified in a financing order issued to a public utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the public utility and created for the limited purpose of acquiring, owning, or administering energy transition property or issuing energy transition bonds under the financing order. All or any portion of energy transition property may be pledged to secure energy transition bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in, or pledge of energy transition property by a public utility, or an affiliate of the public utility, to an assignee, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission.

d. If a public utility defaults on any required payment of charges arising from energy transition property specified in a financing order, a court, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the energy transition property to the financing parties or their assignees. Any such financing order remains in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the public utility or its successors or assignees.

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in energy transition property specified in a financing order issued to a public utility, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by the public utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the public utility or any other entity.

f. Any successor to a public utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of public utility restructuring or otherwise, must perform and satisfy all obligations of, and have the same rights under a financing order as, the public utility under the financing order in the same manner and to the same extent as the public utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the energy transition property. Nothing in this sub-subdivision is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities.

g. Energy transition bonds shall be nonrecourse to the credit or any assets of the public utility other than the energy transition property as specified in the financing order and any rights under any ancillary agreement.

(2) Provisions applicable to security interests. –

a. The creation, perfection, and enforcement of any security interest in energy transition property to secure the repayment of the principal and interest and other amounts payable in respect of energy transition bonds; amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not by the provisions of the Code.

b. A security interest in energy transition property is created, valid, and binding and perfected at the later of the time (i) the financing order is issued, (ii) a security agreement is executed and delivered by the debtor granting such security interest, (iii) the debtor has rights in such energy transition property or the power to transfer rights in such energy transition property, or (iv) value is received for the energy transition property. The description of energy transition property in a security agreement is sufficient if the description refers to this section and the financing order creating the energy transition property.

c. A security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of a financing statement with the office of the Secretary of State, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the energy transition property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section.

d. The Secretary of State shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code.

e. The priority of a security interest in energy transition property is not affected by the commingling of energy transition charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all energy transition charges that are deposited in any cash or deposit account of the qualifying utility in which energy transition charges have been commingled with other funds, and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

f. No application of the formula-based adjustment mechanism as provided in this section will affect the validity, perfection, or priority of a security interest in or transfer of energy transition property.

g. If a default or termination occurs under the energy transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any energy transition property as if they were secured parties with a perfected and prior lien under the Code, and the Commission may order amounts arising from energy transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Superior Court of Wake County shall order the sequestration and payment to them of revenues arising from the energy transition charges.

(3) Provisions applicable to the sale, assignment, or transfer of energy transition property. –

a. Any sale, assignment, or other transfer of energy transition property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the energy transition property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and State income tax purposes. For all purposes other than federal and State income tax purposes, the parties' characterization of a transaction as a sale of an interest in energy transition property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of whether the purchaser has possession of any documents evidencing or pertaining to the interest. A transfer of an interest in energy transition property may be created only when all of the following have occurred (i) the financing order creating the energy transition property has become effective, (ii) the documents evidencing the transfer of energy transition property have been executed by the assignor and delivered to the assignee, and (iii) value is received for the energy transition property. After such a transaction, the energy transition property is not subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the energy transition property perfected in accordance with subdivision (2) of this subsection.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser shall not be affected or impaired by the occurrence of any of the following factors:

1. Commingling of energy transition charges with other amounts.
2. The retention by the seller of (i) a partial or residual interest, including an equity interest, in the energy transition property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of energy transition charges.
3. Any recourse that the purchaser may have against the seller.
4. Any indemnification rights, obligations, or repurchase rights made or provided by the seller.
5. The obligation of the seller to collect energy transition charges on behalf of an assignee.
6. The transferor acting as the servicer of the energy transition charges or the existence of any contract that authorizes or requires the public utility, to the extent that any interest in energy transition property is sold or assigned, to contract with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the energy transition charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party.
7. The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes.
8. The granting or providing to bondholders a preferred right to the energy transition property or credit enhancement by the public utility or its affiliates with respect to such energy transition bonds.
9. Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that a public utility has in the energy transition property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order is property in the form of a contract right or a chose in action. Transfer of an interest in energy transition property to an assignee is enforceable only upon the later of (i) the issuance of a financing order, (ii) the assignor having rights in such energy transition property or the power to transfer rights in such energy transition property to an assignee, (iii) the execution and delivery by the assignor of transfer documents in connection with the issuance of energy transition bonds, and (iv) the receipt of value for the energy transition property. An enforceable transfer of an interest in energy transition property to an assignee is perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with sub-subdivision c. of subdivision (2) of this subsection. The transfer is perfected against third parties as of the date of filing.

d. The Secretary of State shall maintain any financing statement filed to perfect any sale, assignment, or transfer of energy transition property under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code. The filing of such a financing statement is the only method of perfecting a transfer of energy transition property.

e. The priority of a transfer perfected under this section is not impaired by any later modification of the financing order or energy transition property or by the commingling of funds arising from energy transition property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision (2) of this subsection, is terminated when they are transferred to a segregated account for the assignee or a financing party. If energy transition property has been transferred to an assignee or financing party, any proceeds of that property must be held in trust for the assignee or financing party.

f. The priority of the conflicting interests of assignees in the same interest or rights in any energy transition property is determined as follows:

1. Conflicting perfected interests or rights of assignees rank according to priority in time of perfection. Priority dates from the time a filing covering the transfer is made in accordance with sub-subdivision c. of subdivision (2) of this subsection.
2. A perfected interest or right of an assignee has priority over a conflicting unperfected interest or right of an assignee.
3. A perfected interest or right of an assignee has priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

(f) Description or Indication of Property. – The description of energy transition property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement is only sufficient if such description or indication refers to the financing order that created the energy transition property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section applies to all purported transfers of, and all purported grants or liens or security interests in, energy transition property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

(g) Financing Statements. – All financing statements referenced in this section are subject to Part 5 of Article 9 of the Code, except that the requirement as to continuation statement does not apply.

(h) Choice of Law. – The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any energy transition property shall be the laws of this State.

(i) Energy Transition Bonds Not Public Debt. – Neither the State nor its political subdivisions are liable on any energy transition bonds, and the bonds are not a debt or a general obligation of the State or any of its political subdivisions, agencies, or instrumentalities, nor are they special obligations or indebtedness of the State or any agency or political subdivision. An issue of energy transition bonds does not, directly, indirectly, or contingently, obligate the State or any agency, political subdivision, or instrumentality of the State to levy any tax or make any appropriation for payment of the energy transition bonds, other than in their capacity as consumers of electricity. All energy transition bonds must contain on the face thereof a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of North Carolina is pledged to the payment of the principal of, or interest on, this bond."

(j) Legal Investment. – All of the following entities may legally invest any sinking funds, moneys, or other funds in energy transition bonds:

(1) Subject to applicable statutory restrictions on State or local investment authority, the State, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission.

(2) Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business.

(3) Personal representatives, guardians, trustees, and other fiduciaries.

(4) All other persons authorized to invest in bonds or other obligations of a similar nature.

(k) Obligation of Nonimpairment. –

(1) The State and its agencies, including the Commission, pledge and agree with bondholders, the owners of the energy transition property, and other financing parties that the State and its agencies will not take any action listed in this subdivision. This paragraph does not preclude limitation or alteration if full compensation is made by law for the full protection of the energy transition charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the public utility. The prohibited actions are as follows:

a. Alter the provisions of this section, which authorize the Commission to create an irrevocable contract right or a chose in action by the issuance of a financing order, to create energy transition property, and make the energy transition charges imposed by a financing order irrevocable, binding, or nonbypassable charges.

b. Take or permit any action that impairs or would impair the value of energy transition property or the security for the energy transition bonds or revises the energy transition costs for which recovery is authorized.

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties.

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair energy transition charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related energy transition bonds have been paid and performed in full.

(2) Any person or entity that issues energy transition bonds may include the language specified in this subsection in the energy transition bonds and related documentation.

(*l*) Not a Public Utility. – An assignee or financing party is not a public utility or person providing electric service by virtue of engaging in the transactions described in this section.

(m) Conflicts. – If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in energy transition property, this section shall govern.

(n) Consultation. – In making determinations under this section, the Commission or public staff or both may engage an outside consultant and counsel.

(o) Effect of Invalidity. – If anyprovision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity of any action allowed under this section which is taken by a public utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement; and any such action remains in full force and effect with respect to all energy transition bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason."

SECTION 2.(b) G.S. 25-9-109 reads as rewritten:

"**§ 25-9-109. Scope.**

(a) General scope of Article. – Except as otherwise provided in subsections (c) and (d) of this section, this Article applies ~~to:~~to all of the following:

(1) A transaction, regardless of its form, that creates a security interest in personal property or fixtures by ~~contract;~~contract.

(2) An agricultural ~~lien;~~lien.

(3) A sale of accounts, chattel paper, payment intangibles, or promissory ~~notes;~~notes.

(4) A ~~consignment;~~consignment.

(5) A security interest arising under G.S. 25-2-401, 25-2-505, 25-2-711(3), or 25-2A-508(5), as provided in ~~G.S. 25-9-110; and~~G.S. 25-9-110.

(6) A security interest arising under G.S. 25-4-208 or G.S. 25-5-118.

(b) Security interest in secured obligation. – The application of this Article to a security interest in a secured obligation is not affected by the fact that the obligation is itself secured by a transaction or interest to which this Article does not apply.

(c) Extent to which Article does not apply. – This Article does not apply to the extent ~~that:~~that any one or more of the following conditions are met:

(1) A statute, regulation, or treaty of the United States preempts this ~~Article;~~Article.

(2) Repealed by Session Laws 2001-218, s. 2, effective July 1, 2001.

(3) A statute of another state, a foreign country, or a governmental unit of another state or a foreign country, other than a statute generally applicable to security interests, expressly governs creation, perfection, priority, or enforcement of a security interest created by the state, country, or governmental ~~unit; or~~unit.

(4) The rights of a transferee beneficiary or nominated person under a letter of credit are independent and superior under G.S. 25-5-114.

(d) Inapplicability of Article. – This Article does not apply ~~to:~~to any of the following:

(1) A landlord's lien, other than an agricultural ~~lien;~~lien.

(2) A lien, other than an agricultural lien, given by statute or other rule of law for services or materials, but G.S. 25-9-333 applies with respect to priority of the ~~lien;~~lien.

(3) An assignment of a claim for wages, salary, or other compensation of an ~~employee;~~employee.

(4) A sale of accounts, chattel paper, payment intangibles, or promissory notes as part of a sale of the business out of which they ~~arose;~~arose.

(5) An assignment of accounts, chattel paper, payment intangibles, or promissory notes which is for the purpose of collection ~~only;~~only.

(6) An assignment of a right to payment under a contract to an assignee that is also obligated to perform under the ~~contract;~~contract.

(7) An assignment of a single account, payment intangible, or promissory note to an assignee in full or partial satisfaction of a preexisting ~~indebtedness;~~indebtedness.

(8) A transfer of an interest in or an assignment of a claim under a policy of insurance, other than an assignment by or to a health-care provider of a health-care-insurance receivable and any subsequent assignment of the right to payment, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(9) An assignment of a right represented by a judgment, other than a judgment taken on a right to payment that was ~~collateral;~~collateral.

(10) A right of recoupment or setoff, ~~but:~~but (i) G.S. 25-9-340

~~a.~~ ~~G.S. 25-9-340~~ applies with respect to the effectiveness of rights of recoupment or setoff against deposit ~~accounts; and~~accounts and (ii) G.S. 25-9-404

~~b.~~ ~~G.S. 25-9-404~~ applies with respect to defenses or claims of an account ~~debtor;~~debtor.

(11) The creation or transfer of an interest in or lien on real property, including a lease or rents thereunder, except to the extent that provision is made ~~for:~~for the following:

a. Liens on real property in G.S. 25-9-203 and ~~G.S. 25-9-308;~~G.S. 25-9-308.

b. Fixtures in ~~G.S. 25-9-334;~~G.S. 25-9-334.

c. Fixture filings in G.S. 25-9-501, 25-9-502, 25-9-512, 25-9-516, and ~~25-9-519; and~~25-9-519.

d. Security agreements covering personal and real property in ~~G.S. 25-9-604;~~G.S. 25-9-604.

(12) An assignment of a claim arising in tort, other than a commercial tort claim, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(13) An assignment of a deposit account in a consumer transaction, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in ~~proceeds;~~proceeds.

(14) The creation, perfection, priority, or enforcement of any lien on, assignment of, pledge of, or security in, any revenues, rights, funds, or other tangible or intangible assets created, made, or granted by this State or a governmental unit in this State, including the assignment of rights as secured party in security interests granted by any party subject to the provisions of this Article to this State or a governmental unit in this State, to secure, directly or indirectly, any bond, note, other evidence of indebtedness, or other payment obligations for borrowed money issued by, or in connection with, installment or lease purchase financings by, this State or a governmental unit in this State. However, notwithstanding this subdivision, this Article does apply to the creation, perfection, priority, and enforcement of security interests created by this State or a governmental unit in this State in equipment or ~~fixtures; or~~fixtures.

(15) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any storm recovery property as defined in G.S. 62-172.

(16) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any energy transition property as defined in G.S. 62-173."

SECTION 2.(c) This section is effective when it becomes law.

ADVANCED NUCLEAR EARLY SITE PERMIT AND SUBSEQUENT LICENSE RENEWAL

SECTION 3.(a) In order to support a diverse portfolio of advanced energy technologies, reduce future permitting and siting costs, and promote the development of advanced nuclear energy, the electric public utilities operating in this State may jointly or separately incur costs up to an aggregate total of fifty million dollars ($50,000,000) to pursue an Early Site Permit (ESP) from the Nuclear Regulatory Commission for siting of an advanced nuclear facility at a single location in the State. The electric public utilities shall make reasonable efforts to obtain any funding available from any federal agencies in order to offset such costs, and any such funding obtained from a federal agency shall be utilized to offset the costs incurred. Each participating electric public utility may establish a regulatory asset and defer to such regulatory asset the incremental costs incurred in connection with its pursuit of an ESP, along with associated carrying costs based on the utility's then-authorized, net-of-tax, weighted average cost of capital, until such time as the costs can be reflected in customer rates. In a future general rate proceeding, the Commission shall establish an amortization period for recovery, and allow a return on the unamortized balance at the utility's then authorized, net-of-tax, weighted average cost of capital. This section shall not be construed to provide any legislative endorsement for the selection of nuclear resources in future electric public utility integrated resource plans, which shall be reviewed by the Commission in accordance with then-applicable laws and regulations.

SECTION 3.(b) In order to support the continued operation of high capacity factor, low-cost, and emissions free nuclear electric generation, the electric public utilities are directed to prepare and submit Subsequent License Renewal applications with the Nuclear Regulatory Commission for each of the six currently operating nuclear electric generating facility sites in the electric public utilities' balancing area authority. The electric public utilities shall report on the status of the Subsequent License Renewal applications in their integrated resource plan filings.

SECTION 3.(c) This section is effective when it becomes law.

PART II. RATE-MAKING MODERNIZATION/AUTHORIZE PERFORMANCE-BASED REGULATION OF ELECTRIC PUBLIC UTILITIES

SECTION 4.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-133.16. Performance-based regulation authorized.**

(a) Definitions. – For purposes of this section, the following definitions apply:

(1) "Cost causation principle" means establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service.

(2) "Decoupling rate-making mechanism" means a rate-making mechanism intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis by its residential customers.

(3) "Distributed energy resource" or "DER" means a device or measure that produces electricity or reduces electricity consumption and is connected to the electric distribution system, either on the customer's premises, or on the electric public utility's primary distribution system. A DER may include any of the following: energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

(4) "Earnings sharing mechanism" means an annual rate-making mechanism that shares surplus earnings between the electric public utility and customers over the period of time covered by a MYRP.

(5) "Multiyear rate plan" or "MYRP" means a rate-making mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application pursuant to G.S. 62-133, along with an earnings sharing mechanism.

(6) "Performance incentive mechanism" or "PIM" means a rate-making mechanism that links electric public utility revenue or earnings to electric public utility performance in targeted areas consistent with policy goals, as that term is defined by this section, approved by the Commission, and includes specific performance metrics and targets against which electric public utility performance is measured.

(7) "Performance-based regulation" or "PBR" means an alternative rate-making approach that includes decoupling, one or more performance incentive mechanisms, and a multiyear rate plan, including an earnings sharing mechanism, or such other alternative regulatory mechanisms as may be proposed by an electric public utility.

(8) "Policy goal" means the expected or anticipated achievement of operational efficiency, cost savings, or reliability of electric service that is greater than that which already is required by State or federal law or regulation, including standards the Commission has established by order prior to and independent of a PBR application, provided that, with respect to environmental standards, the Commission may not approve a policy goal that is more stringent than is established (i) by State law, (ii) by federal law, (iii) by the Environmental Management Commission pursuant to G.S. 143B-282, or (iv) by the United States Environmental Protection Agency.

(9) "Rate year" means the year of the MYRP for which base rates are effective.

(10) "Tracking metric" means a methodology for tracking and quantitatively measuring and monitoring outcomes or electric public utility performance.

(b) Performance-Based Regulation Authorized. – In addition to the method for fixing base rates established under G.S. 62-133, the Commission is authorized to approve performance-based regulation upon application of an electric public utility pursuant to the process and requirements of this section, so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle, including the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs between customer classes, and interclass subsidization of ratepayers is minimized to the greatest extent practicable by the conclusion of the MYRP period. This section shall not be construed to require the Commission to use the minimum system methodology for the purpose of classifying costs within a customer class when setting a basic facilities charge.

(c) Application. – An electric public utility shall be permitted to submit a PBR application in a general rate case proceeding initiated pursuant to G.S. 62-133. A PBR application shall include a decoupling rate-making mechanism, one or more PIMs, and a MYRP, including both an earnings sharing mechanism and proposed revenue requirements and base rates for each of the years that a MYRP is in effect or a method for calculating the same. The PBR application may also include proposed tracking metrics with or without targets or benchmarks to measure electric public utility achievement. The following additional requirements apply to a PBR application:

(1) The following shall apply to a MYRP:

a. The base rates for the first rate year of a MYRP shall be fixed in the manner prescribed under G.S. 62-133, including actual changes in costs, revenues or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period, plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year. Subsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period; provided that the amount of increase in the second rate year under the MYRP shall not exceed four percent (4%) of the electric public utility's North Carolina retail jurisdictional revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133 excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year. The amount of increase for the third rate year under the MYRP shall not exceed four percent (4%) of the electric public utility's North Carolina retail jurisdictional revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133, excluding any revenue requirement for the capital spending projects placed in service during the first rate year. The revenue requirements associated with any single new generation plant placed in service during the MYRP for which the total plant in service balance exceeds five hundred million dollars ($500,000,000) shall not be included in a MYRP. Instead, the utility may request and the Commission may grant, if it deems appropriate, permission to establish a regulatory asset and defer to such regulatory asset incremental costs related to such electric generation investments to be considered for recovery in a future rate proceeding. In setting the electric public utility's authorized rate of return on equity for an MYRP period, the Commission shall consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

b. In a proceeding authorizing a MYRP, the Commission shall establish a rider to refund amounts related to the earnings sharing mechanism, and to refund or collect amounts related to PIM rewards or penalties, and decoupling adjustments.

c. Within 60 days of the conclusion of each rate year, the Commission shall establish a proceeding to:

1. Examine the earnings of the electric public utility during the rate year to determine if the earnings exceeded the authorized rate of return on equity determined by the Commission in the proceeding establishing the PBR. If the weather-normalized earnings exceed the authorized rate of return on equity plus 50 basis points, the excess earnings above the authorized rate of return on equity plus 50 basis points will be refunded to customers in the rider established by the Commission. If the weather-normalized earnings fall below the authorized rate of return on equity, the electric public utility may file a rate case pursuant to G.S. 62-133. Any penalties or rewards from PIM incentives and any incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f) will be excluded from the determination of any refund pursuant to earnings sharing mechanism.

2. Evaluate the performance of the electric public utility with respect to Commission approved PIMs applicable in the rate year. Any financial rewards shall be collected from customers and any penalties refunded to customers, in each case, through the rider established by the Commission.

3. Evaluate the decoupling rate-making mechanism, and refund or collect, as applicable, a corresponding amount from residential customers through the rider established by the Commission.

(2) The proposed decoupling mechanism shall only be applied to residential customer classes. The Commission shall establish an annual revenue requirement per residential customer and an appropriate distribution of said revenue requirement per customer in each month of the year. The established monthly revenue requirements times the actual number of residential customers each month shall become the target revenue for the residential class. Each month, the electric public utility shall defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class. The changes in revenue requirements for the second and third rate years shall be allocated to the residential customer class and divided by the number of residential customers to determine the appropriate adjustment to the annual revenue requirement per residential customer that is used to establish the target revenues for the residential class in the second and third rate years of a MYRP. The electric public utility may

exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption.

(3) The policy goal targeted by a PIM shall be clearly defined, measurable with a defined performance metric, and solely or primarily within the electric public utility's control.

(4) Any PIM shall be structured to ensure that, pursuant to subdivisions (1) and (2) of this subsection, any penalty shall be refunded to customers and any reward shall be collected from customers and shall be limited such that the total of all potential and actual PIM incentives or penalties does not exceed one percent (1%) of the electric public utility's total annual revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133, excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year, where the PIM is approved. Any incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f) shall be excluded from the limits established in this section and shall continue to be recovered through the demand-side management and energy efficiency (DSM/EE) rider.

(5) Subject to the limitations set out in the preceding subdivision, any PIMs proposed by an electric public utility shall include one or more of the following:

a. Rewards based on the sharing of savings achieved by meeting or exceeding a specific policy goal.

b. Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet a specific policy goal, which shall not be greater than 25 basis points.

c. Fixed financial rewards to encourage achievement of specific policy goals, or fixed financial penalties for failure to achieve policy goals.

(d) Commission Action on Application. –

(1) The Commission shall approve a PBR application by an electric public utility only upon a finding that a proposed PBR would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in this section and rules adopted thereunder. In reviewing any such PBR application under this section, the Commission shall consider whether the PBR application:

a. Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.

b. Reasonably assures the continuation of safe and reliable electric service.

c. Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

(2) In reviewing any such PBR application under this section, the Commission may consider whether the PBR application:

a. Encourages peak load reduction or efficient use of the system.

b. Encourages utility-scale renewable energy and storage.

c. Encourages DERs.

d. Reduces low-income energy burdens.

e. Encourages energy efficiency.

f. Encourages carbon reductions.

g. Encourages beneficial electrification, including electric vehicles.

h. Supports equity in contracting.

i. Promotes resilience and security of the electric grid.

j. Maintains adequate levels of reliability and customer service.

k. Promotes rate designs that yield peak load reduction or beneficial load-shaping.

(3) When an electric public utility files with the Commission an application for a general rate case pursuant to G.S. 62-133 and that application includes a PBR application, the Commission shall institute proceedings on the application as provided in this subdivision. The electric public utility shall not make any changes in any rate or implement a PBR except upon 30 days' notice to the Commission, and the Commission may require the electric public utility to provide notice of the pending PBR application to the same extent as provided in G.S. 62-134(a) and may suspend the effect of the proposed base rates and PBR implementation pending investigation in the same manner as provided in G.S. 62-134(b), provided that, the Commission may suspend the implementation of the proposed base rates for no longer than 300 days. The electric public utility's application shall plainly state the changes in base rates and the time when the change in rates will go into effect and shall include schedules in the same manner required pursuant to G.S. 62-134(a). The Commission shall, upon reasonable notice, conduct a hearing concerning the lawfulness of the proposed base rates and the PBR application. After hearing, the Commission shall issue an order approving or rejecting the electric public utility's PBR application. The Commission shall not be permitted to modify the PBR application. In the event that the Commission rejects a PBR application, the Commission shall nevertheless establish the electric public utility's base rates in accordance with G.S. 62-133 based on the PBR application. If the Commission rejects the PBR application, it shall provide an explanation of the deficiency and an opportunity for the electric public utility to refile, or for the electric public utility and the stakeholders to collaborate to cure the identified deficiency and refile.

(e) Commission Review. – At any time prior to expiration of a PBR plan period, the Commission, with good cause and upon its own motion or petition by the Public Staff, may examine the reasonableness of an electric public utility's rates under a plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust base rates or PIMs as necessary. In addition, the approval of a PBR shall not be construed to limit the Commission's authority to grant additional deferrals between rate cases for extraordinary costs not otherwise recognized in rates.

(f) Plan Period. – Any PBR application approved pursuant to this section shall remain in effect for a plan period of not more than 36 months.

(g) Commission Authority Preserved. – Nothing in this section shall be construed to (i) limit or abrogate the existing rate-making authority of the Commission or (ii) invalidate or void any rates approved by the Commission prior to the effective date of this section. In all respects, the alternative rate-making mechanisms, designs, plans, or settlements shall operate independently, and be considered separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless otherwise incorporated into such plan.

(h) Utility Reporting. – For purposes of measuring an electric public utility's earnings under a PBR application approved under this section, an electric public utility shall make an annual filing that sets forth the electric public utility's earned return on equity, the electric public utility's revenue requirement trued-up with the actual electric public utility revenue, the amount of revenue adjustment in terms of customer refund or surcharge, if applicable, and the adjustments reflecting rewards or penalties provided for in PIMs approved by the Commission.

(i) Commission Report. – No later than April 1 of each year, the Commission shall submit a report on the activities taken by the Commission to implement, and by electric public utilities to comply with, the requirements of this section to the Governor, the Environmental Review Commission, the Joint Legislative Commission on Energy Policy, the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources, and the chairs of the House Committee on Energy and Public Utilities. The report shall include a summary of public comments received by the Commission. In developing the report, the Commission shall consult with the Department of Environmental Quality.

(j) Rulemaking. – The Commission shall adopt rules to implement the requirements of this section. Rules adopted shall include all of the following matters:

(1) The specific procedures and requirements that an electric public utility shall meet when requesting approval of a PBR application.

(2) The criteria for evaluating a PBR application.

(3) The parameters for a technical conference process to be conducted by the Commission prior to submission of any PBR application consisting of one or more public meetings at which the electric public utility presents information regarding projected transmission and distribution expenditures and interested parties are permitted to provide comment and feedback; provided, however, no cross-examination of parties shall be permitted. The technical conference process to be established shall not exceed a duration of 60 days from the date on which the electric public utility requests initiation of such process.

(4) In the event the Commission rejects a PBR application, the process by which an electric public utility may address the Commission's reasons for rejection of a PBR application, which process may include collaboration between stakeholders and the electric public utility to cure any identified deficiency in an electric public utility's PBR application."

SECTION 4.(b) The Commission shall adopt rules as required by G.S. 62-133.16(j), as enacted by subsection (a) of this section, no later than 120 days after the date this section becomes law.

SECTION 4.(c) This section is effective when it becomes law and applies to any rate-making mechanisms filed by an electric public utility on or after the date that rules adopted pursuant to G.S. 62-133.16, as enacted by subsection (a) of this section, become effective.

PART III. CUSTOMER RENEWABLES PROGRAMS

GREEN SOURCE ADVANTAGE

SECTION 5. G.S. 62-159.2 reads as rewritten:

"**§ 62-159.2. Direct renewable energy procurement for major military installations, public universities, and large customers.**

(a) Each electric public utility providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2017, shall file with the Commission an application requesting approval of a new program applicable to major military installations, as that term is defined in G.S. 143-215.115(1), The University of North Carolina, as established in Article 1 of Chapter 116 of the General Statutes, and other new and existing nonresidential customers with either a contract demand (i) equal to or greater than one megawatt (MW) or (ii) at multiple service locations that, in aggregate, is equal to or greater than five megawatts (MW).

(b) Each electric public utility's program ~~application~~ required by this section shall provide standard contract terms and conditions for participating customers and for renewable energy suppliers from which the electric public utility procures energy and capacity on behalf of the participating customer. The ~~application~~ program shall allow eligible customers to select the new renewable energy facility from which the electric public utility shall procure energy and capacity. The standard terms and conditions available to renewable energy suppliers shall provide a range of terms, between two years and 20 years, from which the participating customer may elect. Eligible customers shall be allowed to negotiate with renewable energy suppliers regarding price terms.

(c) ~~Each contracted amount of capacity shall be limited to no more than one hundred twenty-five percent (125%) of the maximum annual peak demand of the eligible customer premises.~~ All agreements executed under this program prior to January 1, 2021, shall remain in full force and effect and shall not be deemed modified or altered in any respect.

(c1) In the case of any participating customer that has not entered into an agreement under this program on or before January 1, 2021, all of the following shall apply:

(1) The reasonably projected first year annual energy output of any renewable energy facility or facilities selected by or procured on behalf of a participating customer shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation. Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility, and participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(2) No single generating facility selected by or procured on behalf of a participating customer shall exceed 80 megawatts alternating current (MW AC) in capacity.

(3) The electric public utility, the participating customer, and the owner of any renewable energy facility or facilities selected by or procured on behalf of a participating customer shall enter into an agreement providing that all environmental and renewable energy attributes generated by such facilities shall be transferred to the participating customer for retirement or retired on the customer's behalf.

(c2) Each public utility shall establish reasonable credit requirements for financial assurance for renewable energy suppliers and eligible customers that are consistent with the Uniform Commercial Code of North Carolina. Major military installations and The University of North Carolina are exempt from the financial assurance requirements of this section.

(d) The program shall be offered by the electric public utilities subject to this section for a period of five years or until December 31, 2022, whichever is later, and shall not exceed a combined 600 megawatts ~~(MW)~~ alternating current (MW AC) of total capacity. For the public utilities subject to this section, where a major military installation is located within its Commission-assigned service territory, at least 100 megawatts (MW) of new renewable energy facility capacity offered under the program shall be reserved for participation by major military installations. At least 250 megawatts ~~(MW)~~ alternating current (MW AC) of new renewable energy facility capacity offered under the programs shall also be reserved for participation by The University of North Carolina. Major military installations and The University of North Carolina must fully subscribe to all their allocations prior to December 31, ~~2020, or a period of no more than three years after approval of the program, whichever is later.~~ 2022. If any portion of total capacity set aside to major military installations or The University of North Carolina is not used, it shall be reallocated for use by any eligible program participant. If any portion of the

600 megawatts ~~(MW)~~ alternating current (MW AC) of renewable energy capacity provided for in this section is not awarded prior to the expiration of the program, it shall be reallocated to and included in a competitive procurement in accordance with G.S. 62-110.8(a).

(e) In addition to the participating customer's normal retail bill, the total cost of any renewable energy and capacity procured by or provided by the electric public utility for the benefit of the program customer shall be paid by that customer. The electric public utility shall pay the owner of the renewable energy facility which provided the electricity. ~~The program customer shall receive a bill credit for the energy as determined by the Commission; provided, however, that the bill credit shall not exceed utility's avoided cost. The Commission shall ensure that all other customers are held neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer.~~ In the case of any customer that enters into an agreement under this program after the effective date of this section, the customer shall be entitled to select one of the following bill credit options:

(1) A bill credit equal to the hourly real time avoided cost or day ahead avoided cost.

(2) A bill credit equal to avoided cost as determined in a manner consistent with the most recent Commission-approved methodology for a period of two, five, or 10 years, as selected by the customer.

(f) Major military installations and The University of North Carolina shall be entitled to participate in the program as described in subsections (b) through (e) of this section, or in accordance with the following terms and conditions:

(1) On or before December 31, 2021, The University of North Carolina may provide written notice to the electric public utility of its intent to participate in the program and its desired capacity amount, not to exceed 250 megawatts alternating current (MW AC) of renewable energy capacity, and major military installations may provide written notice to the electric public utility of their intent to participate in the program and their desired capacity amount, not to exceed 100 megawatts alternating current (MW AC) of renewable energy capacity.

(2) Upon receipt of written notice provided in accordance with subdivision (1) of this subsection, the electric public utility shall competitively procure from independent third parties renewable energy and capacity from one or more renewable energy facilities to provide the total amount of renewable energy capacity requested by The University of North Carolina and major military installations utilizing the competitive procurement process set forth in G.S. 62-110.8 for procurements occurring on or after January 1, 2022. The electric public utility shall enter into a power purchase agreement with one or more renewable facilities selected through such competitive procurement, provided that the price to be paid under the power purchase agreement, inclusive of network upgrades, shall not exceed the electric public utility's avoided cost as determined in a manner consistent with the most recent Commission-approved methodology for a period of 20 years. The applicable power purchase agreement shall allow the procuring electric public utility rights to dispatch, operate, and control the renewable energy facilities in the same manner as the electric public utility's own generating resource. Where necessary, the electric public utility may allocate a renewable energy facility between the major military installations and The University of North Carolina. In the event that an insufficient amount of qualifying bids are received in the initial procurement event or the electric public utility is otherwise unable to procure the requested amount of capacity, the electric public utility may

conduct subsequent procurements at a reasonably determined time to attempt to procure the full amount of requested capacity.

(3) In addition to their normal retail bill, the major military installations and The University of North Carolina shall pay a product charge equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively. The electric public utility shall pay the owner of the renewable energy facility or facilities selected through such competitive procurement at the price established through the competitive procurement. The major military installations and The University of North Carolina shall be entitled to a bill credit equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively.

(4) In the event that the electric public utility is prohibited, for purposes of compliance with a future federal or State law, rule, or regulation relating to air emissions or renewable energy or clean energy, from relying on or otherwise receiving credit for any renewable generating facility procured under this program for a major military installation or The University of North Carolina, the electric public utility shall be entitled after the first two years of the contract term to terminate the agreement with the participating customer on 90 days' written notice to the participating customer if the Commission determines that the offering utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource. In the event of any such termination, to the greatest extent reasonably possible and subject to Commission approval, the utility shall seek to enter into a replacement arrangement with such customer that provides the customer with a set of rights that is as close as possible to the initial arrangement while still allowing the utility to comply with the federal or State law, rule, or regulation related to air emissions or renewable energy or clean energy generation."

SHARED SOLAR/COMMUNITY SOLAR GARDENS

SECTION 6.(a) G.S. 62-126.3 reads as rewritten:

"**§ 62-126.3. Definitions.**

For purposes of this Article, the following definitions apply:

(1) Affiliate. – Any entity directly or indirectly controlling or controlled by or under direct or indirect common control with an electric power supplier.

(2) Commission. – The North Carolina Utilities Commission.

~~(3) Community solar energy facility. – A solar energy facility whose output is shared through subscriptions.~~

(4) Customer generator. – An owner, operator, or customer-generator lessee of a solar energy facility or other renewable energy facility, including any equipment that enhances the use of that facility such as an energy storage device, provided that the storage device is charged solely from that facility, that is taking service under the terms and conditions of a net metering tariff approved by the Commission, including a tariff authorized under G.S. 62-126.4A.

(4a) Customer generator lessee. – A lessee of a solar energy facility.

(5) Electric generator lessor. – The owner of solar energy facility that leases the facility to a customer generator lessee, including any agents who act on behalf of the electric generator lessor. For purposes of this Article, an electric generator lessor shall not be considered a public utility under G.S. 62-3(23).

(6) Electric power supplier. – A public utility, an electric membership corporation, or a municipality that sells electric power to retail electric customers in the State.

(7) Electric public utility. – A public utility as defined by G.S. 62-3(23) that sells electric power to retail electric customers in the State.

(7a) Government customer. – A governmental customer that receives retail electric service from an electric public utility.

(7b) Large commercial or industrial customer. – A commercial or industrial retail customer of an electric public utility whose annual peak demand is more than 5 megawatts.

…

(9) Net metering. – To use electrical metering equipment to measure the difference between the electrical energy supplied to a retail electric customer by an electric power supplier and the electrical energy supplied by the retail electric customer to the electric power supplier over the applicable billing period. A solar choice tariff authorized under G.S. 62-126.4A shall prospectively constitute an electric public utility's net metering arrangement for new customer participation after its effective date.

(10) Offering utility. – ~~Any~~ Except as specifically defined in G.S. 62-126.4A and G.S. 62-126.8A, an offering utility is any electric public utility as defined in G.S. 62-3(23) serving at least 150,000 North Carolina retail jurisdictional customers as of January 1, ~~2017.~~ 2021. The term shall not include any other electric public utility, electric membership corporation, or municipal electric supplier authorized to provide retail electric service within the State. An offering utility's participation in this Article as an electric generator lessor shall not otherwise alter its status as a public utility with respect to any other provision of this Chapter. An offering utility's participation in this Article shall be regulated pursuant to the provisions of this Article.

…

(13a) Small commercial or industrial customer. – A commercial or industrial retail customer of an electric public utility whose annual peak demand is less than or equal to 5 megawatts but excluding government customers.

…."

SECTION 6.(b) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.8B. Shared solar program.**

(a) It is the policy of the State to encourage electric public utilities to provide expanded renewable energy options for North Carolina large commercial or industrial customers, small commercial or industrial customers, units of local government, and residential customers and to foster the use of renewable energy as part of the electric public utilities' generation mix. Therefore, electric public utilities providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, shall jointly or separately complete a competitive procurement seeking new solar resources in a total amount of approximately 750 megawatts alternating current (MW AC) procured over a period of approximately three years. All the following shall apply to such procurements:

(1) The offering utilities shall enter into power purchase agreements (PPA) with the selected solar generating facilities. PPAs shall be for a period of 20 years and shall provide for the purchase of all the energy, capacity, and all environmental and renewable energy attributes. The applicable PPA shall allow the procuring electric public utility rights to dispatch, operate, and

control the renewable energy facilities in the same manner as the electric public utility's own generating resources.

(2) The offering utilities may require the renewable generation facilities procured hereunder to meet commercially reasonable performance standards. The offering utilities and their affiliates shall not participate as bidders in the competitive solicitation process required under this section.

(3) Renewable generation facilities procured pursuant to this subsection shall be new solar generating facilities and located within the respective balancing authority areas of the electric public utilities, whether located inside or outside the geographic boundaries of the State. Each facility shall be connected to the electric public utility's transmission system and shall have a capacity of no more than 80 megawatts alternating current (MW AC). The price paid under the PPA shall not exceed the electric public utility's current forecast of its avoided cost calculated over the term of the PPA, inclusive of any upgrade costs. The electric public utility's current forecast of its avoided cost shall be consistent with the Commission-approved avoided cost methodology.

(b) Each offering utility shall file with the Commission an application requesting approval of a shared solar program. The Commission shall issue a final decision approving, modifying, or rejecting the program within 120 days of receipt of the application. Each shared solar program shall conform with all of the following:

(1) Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility, and participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(2) Capacity under the program shall be opened for a defined initial enrollment period during each program procurement cycle. If any program class is oversubscribed during the initial enrollment period, all of the following shall apply:

a. In the case of large commercial or industrial customers and government customers, the available capacity shall be allocated to all eligible customers that applied on a proportional basis based on the requested subscription amount of each customer.

b. In the case of small commercial or industrial and residential customers, the available capacity shall be allocated through a random selection process.

(3) The total program volume shall be allocated as follows: seventy percent (70%) to large commercial or industrial customers and small commercial or industrial customers, twenty percent (20%) to government customers, and ten percent (10%) to residential customers. To the extent that any customer class has not fully subscribed to its respective allocation within the initial enrollment period, any unsubscribed amount shall be made available to all eligible customers through a second enrollment period and, if oversubscribed during such second enrollment period, shall be allocated through a random selection process. Thereafter, any remaining capacity from such procurement cycle shall be made available on a first come, first served basis.

(4) The reasonably projected first year's annual energy output from a participating customer's capacity allocation from the program shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation.

(5) Once a subscription has been awarded, the subscription shall remain in place until the earlier of the following:

a. The customer terminates their subscription.

b. The customer cancels their retail service.

c. Twenty years after the solar generating facility to which such customer has been subscribed achieved commercial operation.

(6) Each participating customer shall pay a product charge equal to the average contract price for all facilities with which the offering utility has contracted in a particular procurement cycle pursuant to the applicable competitive solicitation.

(7) Each participating customer shall receive a bill credit equal to the product charge for such customer.

(8) All environmental and renewable energy attributes produced by any shared renewables facility associated with the customer's participation in the program shall be retired by the offering utility on behalf of the participating customer or, at the election of a nonresidential participating customer, be conveyed to the customer for retirement, at the customer's expense, in which case, the customer must provide proof of retirement within 90 days. In the event that the utility is prohibited, for purposes of compliance with a future federal or State law or regulation relating to air emissions or renewable energy or clean energy, from relying on or otherwise receiving credit for a renewable generating facility that is procured under this program, the utility shall be entitled after the first two years of the program term to terminate the agreement with such participating customer on 90 days' written notice to the participating customer if the Commission determines that the utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource. In the event of any such termination, to the greatest extent reasonably possible and subject to Commission approval, the utility shall seek Commission approval of a replacement arrangement with such customer that provides the customer with a set of rights that is as close as possible to the initial arrangement while still allowing the utility to comply with such federal or State law or regulation related to air emissions or renewable energy or clean energy generation.

(9) Each participating customer shall pay a reasonable administration fee approved by the Commission in order for the offering utility to recover the administrative costs of the program."

SECTION 6.(c) G.S. 62-126.8 is repealed.

SECTION 6.(d) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.8A. Community solar gardens.**

(a) Procurement. – In order to provide expanded solar energy options for North Carolina small commercial and industrial customers and residential customers and to foster the use of solar energy as part of the electric public utilities' generation mix, electric public utilities subject to this section shall undertake a competitive procurement of solar energy for the purpose of offering a community solar gardens program for participation by small commercial and industrial, government, and residential customers. For purposes of this section, an "offering utility" includes any electric public utility serving more than 100,000 retail electric customers in the State as of January 1, 2021. Aggregate procurement shall be as follows:

(1) Electric public utilities providing retail electric service to more than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, shall

jointly or separately complete a competitive procurement seeking up to 50 megawatts (MW) of new distribution-connected solar generation to be utility-owned. To the extent practicable, approximately equal amounts of solar generation shall be procured under this program in each of their respective service territories.

(2) An electric public utility providing retail electric service to more than 100,000 and fewer than 150,000 North Carolina retail jurisdictional customers as of January 1, 2021, may elect to offer a competitive procurement seeking up to 10 megawatts (MW) of new distribution-connected solar generation to be utility-owned. For purposes of this section, such electric utility shall also be an "offering utility."

(b) The initial procurements required by this section shall be completed within 60 days of the date on which the Commission approves the program pursuant to subsection (c) of this section. Each offering utility implementing this section shall attempt to procure at least twenty-five percent (25%) of its total procurement amount from projects that are capable of being placed into service on or before December 31, 2023, for the purpose of offering a community solar gardens program for participation by its small commercial and industrial, government, and residential customers. Each offering utility shall be permitted to require that solar generation facilities procured under this section meet commercially reasonable performance and technical standards. An offering utility and its affiliates shall not participate as bidders in the competitive request for proposals process required under this section. In the event that an insufficient number of eligible solar generating facilities are procured through such process, an offering utility shall be permitted to propose self-developed solar generating facilities if the capital costs are below the cost cap specified in subsection (e) of this section. To the extent that an offering utility is unable to procure viable projects meeting the required criteria and meeting the total procurement amount specified in subdivisions (1) and (2) of subsection (a) of this section through the initial procurement, and there are no self-developed facilities meeting the criteria identified in this section, the offering utility shall be permitted to conduct another procurement at a later date to meet the total procurement amount.

(c) Eligible Projects. – Solar generation facilities procured pursuant to subsection (a) of this section shall be new solar capacity and located in the State of North Carolina. Each such facility shall be interconnected to the relevant offering utility's distribution system.

(d) Application. – Within 180 days of the effective date of this section, each offering utility shall file with the Commission an application requesting approval of a community solar gardens program. Each community solar gardens program shall conform with the following:

(1) The program volume shall be allocated as follows: thirty-five percent (35%) to small commercial and industrial customers, thirty percent (30%) to government customers, and thirty-five percent (35%) to residential customers. To the extent that any customer class has not fully subscribed to its respective allocation within one year of the opening of the application period, any unsubscribed amount shall be made available to all program applicants based on the priority of their applications, or, to the extent necessary, by random selection process.

(2) The reasonably projected first year's annual energy output from a participating customer's capacity allocation from the program shall not exceed the average annual energy consumption of the eligible customer premises for the most recent three calendar years, or, in the case of premises not in operation for three years, the reasonably projected average annual energy consumption for the first three years of operation.

(3) No single participating customer subscription shall account for more than fifty percent (50%) interest in a single facility, and each facility shall have a minimum of five subscribers.

(4) Participating customers' premises shall be located in the State of North Carolina and in the retail service territory of the offering utility offering the program. Participating customers may only participate in the program offered by the electric public utility that provides such customer with retail service.

(5) Once a subscription has been awarded, such subscription shall remain in place until the earlier of the following:

a. The customer terminates their subscription.

b. The customer cancels their retail service.

c. Twenty years after the solar generating facility to which such customer has been subscribed achieved commercial operation.

(6) Each participating customer shall pay a monthly product charge equal to its pro rata share of the offering utility's monthly levelized revenue requirement for all of the community solar garden facilities serving the relevant offering utility's community solar garden program.

(7) Each participating customer shall pay a reasonable administration fee approved by the Commission in order for the offering utility to recover the administrative costs of the program.

(8) Each offering utility shall provide to each participating customer a monthly bill credit in an amount equal to its pro rata share of the offering utility's monthly levelized revenue requirement for all of the community solar garden facilities. The renewable energy certificates produced by the community solar garden facility associated with the customer's subscription shall be retired by the offering utility on the customer's behalf, provided that government customers may elect to have certificates transferred by the electric public utilities to an account the customer controls but shall be responsible for the cost of such transfer and must provide proof of retirement of the certificates to the electric public utilities within 90 days of receipt, provided, further that in the event that the offering utility is prohibited, for purposes of compliance with a future federal or State law or regulation relating to air emissions or renewable energy or clean energy from relying on or otherwise receiving credit for any solar generating facility procured under the community solar gardens program, the offering utility shall be entitled after the first two years of the program to terminate such program on 90 days written notice to the participating customers if the Commission determines that the offering utility will incur incremental compliance costs due to its inability to rely on or otherwise receive credit for such renewable generation resource or the output of such renewable generation resource.

(e) Cost Recovery. – The capital cost for the construction of projects procured or constructed under this section shall not exceed one dollar and ninety cents ($1.90) per watt AC, inclusive of interconnection costs. If a solar generating facility has been identified for selection and use in the program in accordance with the terms of this section and satisfies the forgoing cost cap, such solar generating facility shall be deemed consistent with the public convenience and necessity for purposes of G.S. 62-110.1, and the Commission shall issue a certificate of public convenience and necessity for such replacement resources in accordance with the process set forth in G.S. 62-111.9(13)(a), and no further process shall be required under G.S. 62-110.1 except as otherwise addressed therein. Each offering utility shall be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all solar generating facilities procured or built under this section until such time as the costs can be reflected in customer rates. The types of incremental costs that may be deferred include operations and maintenance expenses, administration costs, property tax, depreciation expense, income taxes, and carrying costs related to electric plant investments and regulatory assets at the offering utility's then authorized, net-of-tax, weighted average cost of capital.

(f) Bill Credit Adjustment. – If, at any point after the date that is two years from the date on which the program is opened for subscriptions, less than fifty percent (50%) of the available subscriptions have been claimed, any party may petition the Commission to modify a community solar garden program as needed to enhance participation through adjustments to the participating customer product charge and bill credit, and the Commission may so modify the program if the Commission determines that it is in the public interest to do so."

SECTION 6.(e) This section is effective when it becomes law. The applications required to be filed with the Utilities Commission pursuant to G.S. 62-126.8B(b), as enacted by subsection (b) of this section, and G.S. 62-126.8A, as enacted by subsection (d) of this section, shall be filed by the offering utilities no later than 180 days after the effective date of this section.

SOLAR CHOICE TARIFF

SECTION 7.(a) G.S. 62-2 reads as rewritten:

"**§ 62-2. Declaration of policy.**

(a) Upon investigation, it has been determined that the rates, services and operations of public utilities as defined herein, are affected with the public interest and that the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy. It is hereby declared to be the policy of the State of North Carolina:

…

(4) To provide just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and ~~conservation~~ efficient use of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy;

(4a) To provide just and reasonable time-variant rates and other dynamic price offerings to utility customers that are designed to optimize the total cost of energy consumption rather than the total volume of energy consumed;

(4b) To assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities; and to that end to authorize fixing of rates in such a manner as to result in lower costs of new facilities and lower rates over the operating lives of such new facilities by making provisions in the rate-making process for the investment of public utilities in plants under construction;

…."

SECTION 7.(b) G.S. 126-2 reads as rewritten:

"**§ 62-126.2. Declaration of policy.**

The General Assembly of North Carolina finds that as a matter of public policy it is in the interest of the State to encourage time-variant pricing structures to promote net energy metering options and to authorize the leasing of solar energy facilities for retail customers and subscription to shared community solar energy facilities. The General Assembly further finds and declares that in encouraging the time-variant pricing structures to promote net energy metering options and the leasing of and subscription to solar energy facilities pursuant to this act, cross-subsidization should be avoided ~~by holding harmless electric public utilities' customers that do not participate in such arrangements.~~to the greatest extent practicable when balancing the goals of this act. The General Assembly recognizes that due to substantive differences in size, customer bases, access to low-carbon generation, and other factors, this declaration of policy does not apply to electric membership corporations, State-owned electric suppliers, or municipalities that sell electric power to retail customers in the State."

SECTION 7.(c) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-126.4A. Solar choice tariff.**

(a) Each offering utility shall file for Commission approval a solar choice tariff that shall become the exclusive option available to customers that apply for net metering service after Commission approval pursuant to this section. For purposes of this section, an "offering utility" includes all electric public utilities serving more than 100,000 retail electric customer in the State as of January 1, 2021.

(b) To allow the market for customer-sited renewable energy facilities to continue to mature without disruption and in a sustainable manner for participating and non-participating customers, and the State economy as a whole, the Commission shall approve an offering utility's application to establish a solar choice tariff that meets all of the following objectives:

(1) Provides for monthly netting with net exports credited at Commission-approved avoided cost in light of the costs and benefits of the solar choice tariff achieving the objectives of a net metering program except as provided in subdivision (2) of this subsection.

(2) Provides for monthly netting within each pricing period for time-variant and dynamic pricing structures with net exports credited at Commission-approved avoided cost.

(3) Provides rate design options that align the customer generator's ability to achieve bill savings with long-term reductions in the overall cost the offering utility will incur in providing electric service, including, but not limited to, time-variant and dynamic pricing structures.

(4) Reduces cross-subsidization by non-participants through mechanisms that allow offering utilities the opportunity to recover customer costs and distribution costs, including a minimum monthly bill, grid access fee for oversized systems, and non-bypassable charges to recover storm recovery, cybersecurity, and public purpose charges for ratepayer funded programs like energy efficiency, demand side management, and resiliency. Such recovery mechanisms shall not, however, include a standby charge where billing is based on the capacity of the renewable energy system.

(5) Minimizes, to the greatest extent practicable, any intraclass cross-subsidization identified using the offering utility's most recently approved embedded cost of service study.

(6) Encourages customer adoption of other energy savings, demand reduction, or grid services technologies and participation in cost-effective programs that can be offered in conjunction with a solar choice tariff to help lower the cost of providing service and maximize grid benefits.

(c) Customer generators taking service under a preexisting net metering tariff prior to Commission approval of a solar choice tariff pursuant to this section shall have the option to transition to the new solar choice tariff or continue to take service under the offering utility's pre-existing net metering tariff in effect at the time of interconnection of that customer generator's net metering facility until January 1, 2040. After January 1, 2027, a non-bypassable charge based upon the DC capacity of the facility will be added for customers who remain on a pre-existing net metering tariff. This charge shall be designed to collect the base rate increase approved by the Commission after January 1, 2027, that would otherwise not be collected from customer generators taking service under a pre-existing net metering tariff after January 1, 2027.

(d) Nothing in this section prohibits a customer generator that is participating in the offering utility's net metering tariff or solar choice tariff from also participating in a Commission-approved energy efficiency program, grid services program, or other type of distributed energy resource aggregation program.

(e) An offering utility offering a solar choice tariff approved pursuant to this section shall continue to be authorized to fully recover its cost of service, including, but not limited to, (i) all costs to effectuate the solar choice tariff and (ii) any unrecovered non-fuel and variable operations and maintenance costs due to customer generators' participation in the solar choice tariff. Notwithstanding the foregoing, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, shall be exempt from cost recovery authorized by this subsection."

SECTION 7.(d) G.S. 62-126.5(d) reads as rewritten:

"§ 62-126.5. Scope of leasing program in offering utilities' service areas.

…

(d) The total installed capacity of all solar energy facilities on an offering utility's system that are leased pursuant to this section shall not exceed ~~one percent (1%)~~ five percent (5%) of the previous five-year average of the North Carolina retail contribution to the offering utility's coincident retail peak demand. The offering utility may refuse to interconnect customers that would result in this limitation being exceeded. Each offering utility shall establish a program for new installations of leased equipment to permit the reservation of capacity by customer generator lessees, whether participating in a public utility or nonutility lessor's leasing program, on its system, including provisions to prevent or discourage abuse of such programs. Such programs must provide that only prospective individual customer generator lessees may apply for, receive, and hold reservations to participate in the offering utility's leasing program. Each reservation shall be for a single customer premises only and may not be sold, exchanged, traded, or assigned except as part of the sale of the underlying premises."

SECTION 7.(e) G.S. 62-133.8(a) reads as rewritten:

"(a) Definitions. – As used in this section:

…

(4) "Energy efficiency measure" means an equipment, physical, behavioral, or program change implemented by a retail electric customer after January 1, 2007, that ~~results in less energy used~~ reduces the customer's energy requirements from the electric power supplier needed to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy ~~resources.~~ resources, and energy produced by a customer generator as that term is defined under 62-126.3(4). "Energy efficiency measure" does not include demand-side ~~management.~~management or the net monthly exports of energy by a customer under a tariff approved pursuant to G.S. 62-126.4(b).

…."

SECTION 7.(f) Article 6B of Chapter 62 of the General Statutes is amended by adding a new section to read:

"§ 62-126.4B. Standby service required in certain circumstances.

For any customer participating in an offering utility's net metering tariff or solar choice tariff, standby service shall be required for customers installing solar or other behind-the-meter generation with a nameplate generation capacity over 100 kW. For behind-the-meter generation with a planning capacity factor of less than sixty percent (60%), the offering utility shall calculate standby service cost using the customer's standby service demand for the billing month set based on either the nameplate capacity of the installed generation or, where the customer has additional metering equipment installed at the customer's expense, then the standby service demand shall equal the generator gross output that occurs at the billing interval coincident with the customer's maximum demand for the billing month under the participating customer's applicable rate schedule. Notwithstanding the foregoing, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, shall be exempt from the standby charge authorized by this section."

SECTION 7.(g) This section is effective when it becomes law. The solar choice tariff required to be filed with the Utilities Commission pursuant to G.S. 62-126.4A, as enacted by subsection (c) of this section, shall be filed by each offering utility no later than 120 days after the effective date of this section, and the Commission shall issue an order to approve, modify, or deny the program no later than 90 days after the submission of the program by the electric public utility.

POTENTIAL MODIFICATION OF CERTAIN EXISTING POWER PURCHASE AGREEMENTS WITH SMALL POWER PRODUCERS

SECTION 8.(a) In an effort to reduce cost to customers, within 120 days after the effective date of this section, the North Carolina Utilities Commission shall initiate a stakeholder process to provide interested parties the opportunity to establish the rates to be paid by the electric public utilities in connection with the modification of certain existing power purchase agreements of small power producers to present to the Commission that would accomplish both of the following:

(1) Provide small power producers a one-time option to elect, within 180 days of a Commission order authorizing such action, to amend their existing power purchase agreement, extending into a new longer term power purchase agreement for a term equal to the remaining term of the existing power purchase agreement plus an additional 10 years, notwithstanding the contract term limits prescribed in G.S. 62-156(c);

(2) Establish capacity and energy rates to be paid by the electric public utilities that are designed to take into consideration the currently contracted capacity and energy rates, capacity and energy rates to be computed at the time the small power producer elects to exercise the option to amend their existing power purchase agreement as provided for in subdivision (1) of this subsection. In developing these rates, stakeholders shall consider whether use of the developed rates, for purchases from small power producers for an extended future term, are just and reasonable to the electric consumer of the electric utility, and in the public interest.

SECTION 8.(b) For purposes of subsections (a) through (e) of this section, the term "small power producers" means small power producers, as that term is defined under G.S. 62-3(27a), generating solar electricity with a total capacity equal to or less than 5 megawatts alternating current (MW AC) that established a legally enforceable obligation in accordance with the Commission's then applicable requirements on or before November 15, 2016, and have entered into a long-term contract exceeding two years to sell their full output to the interconnected electric public utility under section 210 of the Public Utility Regulatory Policies Act of 1978.

SECTION 8.(c) In conducting the stakeholder process required by this section, the Commission shall convene representatives from all of the following entities:

(1) The Public Staff.

(2) Electric public utilities obligated to purchase capacity and energy from small power producers pursuant to G.S. 62-156.

(3) Small power producers.

SECTION 8.(d) Within 180 days of the Commission's initiation of the stakeholder process, the stakeholders shall present, jointly or separately, their recommendations to the Commission. The Commission shall approve the proposed rates and resulting amended power purchase agreements if the Commission finds that the proposed methodology (i) reduces costs to customers in the short term and over the life of the amended power purchase agreement, evaluated from the date of the amendment through to the end of the amended agreement, (ii) fairly compensates small power producers that elect such treatment, and (iii) is just and reasonable and in the public interest. Notwithstanding the foregoing, it is hereby declared appropriate, in the public interest and promoting of regulatory economy, for small power producers and the electric public utilities to negotiate amendments to the power purchase agreements of such small power producers in lieu of the aforementioned stakeholder process, provided that the intent and objectives of this section are accomplished through such negotiation.

SECTION 8.(e) Notwithstanding the foregoing, it is hereby declared appropriate, in the public interest, and promoting of regulatory economy for small power producers and the electric public utilities to negotiate amendments to the power purchase agreements of such small power producers in lieu of the aforementioned stakeholder process, provided that the intent and objectives of this section are accomplished through such negotiation.

PROHIBIT UNAUTHORIZED EXECUTIVE BRANCH ACTIONS TO PARTICIPATE IN THE REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

SECTION 8.1.

(a) The General Assembly finds the following:

(1) The Regional Greenhouse Gas Initiative (RGGI) is a regional, "market-based" carbon dioxide (CO_2) emissions reduction program among certain states to cap and reduce CO_2 emissions from the fossil fuel-fired electric power generators located within those states. Under the program, fossil fuel-fired electric power generators with a capacity of 25 megawatts (MW) or greater located in signatory states are required to obtain allowances to offset their CO_2 emissions.

(2) Art. 1, § 6 of the State's Constitution provides "[t]he legislative, executive, and supreme judicial powers of the State government shall be forever separate and distinct from each other."

(3) The General Assembly, which comprises the legislative branch, enacts laws that "protect or promote the health, morals, order, safety, and general welfare of society." State v. Ballance, 229 N.C. 764, 769, 51 S.E.2d 731, 734 (1949); see also N.C. Const. art. II, §§ 1, 20. The executive branch, which the Governor leads, faithfully executes, or gives effect to, these laws. See N.C. Const. art. III, §§ 1, 5(4). McCrory v. Berger, 368 N.C. 633, 781 S.E.2d 248 (2016).

(4) The General Assembly has not enacted legislation that would authorize the executive branch to enter into an agreement to participate in RGGI, or similar agreement on behalf of the State, nor implement requirements for emissions limitations and cap and trade attendant with the RGGI program. Absent authorization through an act of the General Assembly, such action by the executive branch would constitute an impermissible infringement of the General Assembly's duty to enact laws that "protect or promote the health, morals, order, safety, and general welfare of society." State v. Ballance, 229 N.C. 764, 769, 51 S.E.2d 731, 734 (1949); see also N.C. Const. art. II, §§ 1, 20.

(b) Until such time as the General Assembly enacts legislation to authorize the State's participation in RGGI, and implementation of emissions limitations and cap and trade requirements attendant with the RGGI program, the executive branch shall be prohibited from taking such action.

PART IV. SEVERABILITY CLAUSE AND EFFECTIVE DATE

SECTION 9. If any provision of this act or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions or applications of this act that can be given effect without the invalid provision or application, and, to this end, the provisions of this act are declared to be severable.

SECTION 10. Except as otherwise provided, this act is effective when it becomes law.

DOCKET NO. E-2, SUB 1287
DOCKET NO. E-7, SUB 1261

VERIFICATION

I, David M. Williamson, being duly sworn, depose and say: I have read the foregoing Response of the Public Staff to Petitions for Program Approval and the facts stated therein are true of my personal knowledge, except as to any matters and things therein stated upon information and belief. As to those, I believe them to be true. I am authorized to sign this verification on behalf of the Public Staff-North Carolina Utilities Commission.

This the 15th day of March, 2022.

David M. Williamson

Sworn to and subscribed before me

This the 15th day of March, 2022.

JESSICA HEIRONIMUS NOTARY PUBLIC WAKE COUNTY, N.C.

Jessica Heironimus
Notary Public
My Commission Expires: May 10, 2023