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SENATE BILL NO. 851

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the House Committee on Labor and Commerce on February 25, 2020)

(Patrons Prior to Substitute—Senators McClellan, Edwards [SB 532], and Marsden [SB 876])

A BILL to amend and reenact §§ 10.1-603.24, 10.1-603.25, 56-576, 56-585.1, 56-594, and 56-596.2 of the Code of Virginia and § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017; to amend the Code of Virginia by adding in Chapter 13 of Title 10.1 an article numbered 4, consisting of sections numbered 10.1-1329 and 10.1-1330, by adding sections numbered 56-585.1:11, 56-585.5, and 56-585.6, and by adding in Chapter 8 of Title 63.2 a section numbered 63.2-806; and to repeal §§ 56-585.1:2 and 56-585.2 of the Code of Virginia, relating to the regulation of electric utilities; ending carbon dioxide emissions; renewable portfolio standards for electric utilities and suppliers; energy efficiency programs and standards; incremental annual energy storage deployment targets; net energy metering; third-party power purchase agreements; and the Manufacturing and Commercial Competitiveness Retention Credit.

Be it enacted by the General Assembly of Virginia:

1. That §§ 10.1-603.24, 10.1-603.25, 56-576, 56-585.1, 56-594, and 56-596.2 of the Code of Virginia and § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, are amended and reenacted and that the Code of Virginia is amended by adding in Chapter 13 of Title 10.1 an article numbered 4, consisting of sections numbered 10.1-1329 and 10.1-1330, by adding sections numbered 56-585.1:11, 56-585.5, and 56-585.6, and by adding in Chapter 8 of Title 63.2 a section numbered 63.2-806 as follows:

Article 1.3.

Virginia ~~Shoreline Resiliency~~ *Community Flood Preparedness* Fund.

§ 10.1-603.24. Definitions.

As used in this article, unless the context requires a different meaning:

"Authority" means the Virginia Resources Authority.

"Cost," as applied to any project financed under the provisions of this article, means the total of all costs incurred by the local government as reasonable and necessary for carrying out all works and undertakings necessary or incident to the accomplishment of any project.

"Department" means the Virginia Department of ~~Emergency Management~~ *Conservation and Recreation*.

"Flood prevention or protection" means the construction of hazard mitigation projects, acquisition of land, or implementation of land use controls that reduce or mitigate damage from coastal or riverine flooding.

"Flood prevention or protection study" means the conduct of a hydraulic or hydrologic study of a flood plain with historic and predicted floods, the assessment of flood risk, and the development of strategies to prevent or mitigate damage from coastal or riverine flooding.

"Fund" means the Virginia ~~Shoreline Resiliency~~ *Community Flood Preparedness* Fund *created pursuant to § 10.1-603.25*.

"Local government" means any county, city, town, municipal corporation, authority, district, commission, or political subdivision created by the General Assembly or pursuant to the Constitution of Virginia or laws of the Commonwealth.

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

"Nature-based solution" means an approach that reduces the impacts of flood and storm events through the use of environmental processes and natural systems. A nature-based solution may provide additional benefits beyond flood control, including recreational opportunities and improved water quality.

§ 10.1-603.25. Virginia Community Flood Preparedness Fund; loan and grant program.

~~There shall be set apart a permanent and perpetual fund, to be known as the~~ *A. The* Virginia Shoreline Resiliency Fund~~, consisting of such~~ *is hereby continued in the state treasury as a special nonreverting fund to be known as the Virginia Community Flood Preparedness Fund. The Fund shall be established on the books of the Comptroller. All sums that are designated for deposit in the Fund from revenue generated by the sale of emissions allowances pursuant to subdivision C 1 of § 10.1-1330, all*

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sums that may be appropriated to the Fund by the General Assembly, all receipts by the Fund from *the repayment of* loans made by it to local governments, all income from the investment of moneys held in the Fund, and any other sums designated for deposit to the Fund from any source, public or private, *including any federal grants and awards or other forms of assistance received by the Commonwealth that are eligible for deposit in the Fund under federal law, shall be paid into the state treasury and credited to the Fund. Interest earned on moneys in the Fund shall remain in the Fund and be credited to it. Any moneys remaining in the Fund, including interest thereon, at the end of each fiscal year shall not revert to the general fund but shall remain in the Fund.* ~~The Fund shall be administered by the Department as prescribed in this article. The Department shall establish guidelines regarding the distribution of loans from the Fund and prioritization of such loans.~~

B. Moneys in the Fund shall be used solely for the purposes of enhancing flood protection and coastal resilience as required by this article. Expenditures and disbursements from the Fund shall be made by the State Treasurer on warrants issued by the Comptroller upon written request signed by the Executive Director of the Authority. The Authority shall manage the Fund and shall establish interest rates and repayment terms of such loans as provided in this article. The Authority may disburse from the Fund its reasonable costs and expenses incurred in the management of the Fund.

C. The Fund shall be administered by the Department as prescribed in this article. The Department, in consultation with the Secretary of Natural Resources and the Special Assistant to the Governor for Coastal Adaptation and Protection, shall establish guidelines regarding the distribution and prioritization of loans and grants, including loans and grants that support flood protection studies of statewide or regional significance.

D. Localities shall use moneys from the Fund primarily for the purpose of ~~creating a low-interest loan program to help residents and businesses~~ *implementing flood prevention and protection projects and studies in areas* that are subject to recurrent flooding as confirmed by a locality-certified floodplain manager. Moneys in the Fund may be used to mitigate future flood damage *and to assist inland and coastal communities across the Commonwealth that are subject to recurrent or repetitive flooding. No less than 25 percent of the moneys disbursed from the Fund each year shall be used for projects in low-income geographic areas. Priority shall be given to projects that implement community-scale hazard mitigation activities and projects that use nature-based solutions to reduce flood risk.*

E. Any locality is authorized to secure a loan made through such a low-interest loan program by placing a lien up to the value of the loan against any property that benefits from the loan. Such a lien shall be subordinate to each prior lien on such property, except prior liens for which the prior lienholder executes a written subordination agreement, in a form and substance acceptable to the prior lienholder in its sole and exclusive discretion, that is recorded in the land records where the property is located.

Article 4.

Clean Energy and Community Flood Preparedness Act.

§ 10.1-1329. Definitions.

As used in this article, unless the context requires a different meaning:

"Allowance" means an authorization to emit a fixed amount of carbon dioxide.

"Allowance auction" means an auction in which the Department or its agent offers allowances for sale.

"DHCD" means the Department of Housing and Community Development.

"DMME" means the Department of Mines, Minerals and Energy.

"Energy efficiency program" has the same meaning as provided in § 56-576.

"Fund" means the Virginia Community Flood Preparedness Fund created pursuant to § 10.1-603.25.

"Housing development" means the same as that term is defined in § 36-141.

"Regional Greenhouse Gas Initiative" or "RGGI" means the program to implement the memorandum of understanding between signatory states dated December 20, 2005, and as may be amended, and the corresponding model rule that established a regional carbon dioxide electric power sector cap and trade program.

"Secretary" means the Secretary of Natural Resources.

§ 10.1-1330. Clean Energy and Community Flood Preparedness.

A. The provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.).

B. The Director is hereby authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article. The Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction, unless the Department finds that doing so will have a negative impact on the value of allowances and result in a net loss of consumer benefit or is otherwise inconsistent with the RGGI program.

C. To the extent permitted by Article X, Section 7 of the Constitution of Virginia, the Department shall (i) hold the proceeds recovered from the allowance auction in an interest-bearing account with all interest directed to the account to carry out the purposes of this article and (ii) use the proceeds without further appropriation for the following purposes:

1. Forty-five percent of the revenue shall be credited to the account established pursuant to the Fund for the purpose of assisting localities and their residents affected by recurrent flooding, sea level rise, and flooding from severe weather events.

2. Fifty percent of the revenue shall be credited to an account administered by DHCD to support low-income energy efficiency programs, including programs for eligible housing developments. DHCD shall review and approve funding proposals for such energy efficiency programs, and DMME shall provide technical assistance upon request. Any sums remaining within the account administered by DHCD, including interest thereon, at the end of each fiscal year shall not revert to the general fund but shall remain in such account to support low-income energy efficiency programs.

3. Three percent of the revenue shall be used to (i) cover reasonable administrative expenses of the Department in the administration of the revenue allocation, carbon dioxide emissions cap and trade program, and auction and (ii) carry out statewide climate change planning and mitigation activities.

4. Two percent of the revenue shall be used by DHCD, in partnership with DMME, to administer and implement low-income energy efficiency programs pursuant to subdivision 2.

D. The Department, the Department of Conservation and Recreation, DHCD, and DMME shall prepare a joint annual written report describing the Commonwealth's participation in RGGI, the annual reduction in greenhouse gas emissions, the revenues collected and deposited in the interest-bearing account maintained by the Department pursuant to this article, and a description of each way in which money was expended during the fiscal year. The report shall be submitted to the Governor and General Assembly by January 1, 2022, and annually thereafter.

E. Notwithstanding any other provision of law, the Board shall adopt regulations to reduce, for the period of 2031 to 2050, the carbon dioxide emissions from any electricity generating unit in the Commonwealth, regardless of fuel type, that serves an electricity generator with a nameplate capacity equal to or greater than 25 megawatts that supplies (i) 10 percent or more of its annual net electrical generation to the electric grid or (ii) more than 15 percent of its annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected (covered unit).

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

To determine the initial allocation amount and rate of reduction in allowance allocations from year to year, the Board shall utilize, and amend as necessary, its existing regulations to reduce carbon dioxide emissions from electric power generating facilities; however, the regulations shall provide that no allowances be issued for covered units in 2045 or any year beyond 2045. The Board may establish rules for trading, the use of banked allowances, and other auction or market mechanisms as it may find appropriate to control allowance costs and otherwise carry out the purpose of this subsection.

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

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

The Board shall promulgate and make effective this regulation no later than July 31, 2025, but shall have authority for subsequent revisions in its discretion and subject to the provisions of this subsection.

§ 56-576. Definitions.

As used in this chapter:

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

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

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

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

"Commission" means the State Corporation Commission.

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

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

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

"Cumulative energy savings" means the total combined kilowatt-hour savings achieved by deployed energy efficiency and demand response measures.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Low-income" means any person or household whose annual income is equal to or less than 80 percent of the lesser of either the state median income as set forth by U.S. Census Bureau's annual "American Community Survey" or the area median income as determined by the US Department of Housing and Community Development.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Subject to the provisions of subdivision 6, the fair rate of return on common equity applicable separately to the generation and distribution services of such utility, and for the two such services combined, and for any rate adjustment clauses approved under subdivision 5 or 6, shall be determined by the Commission during each such triennial review, as follows:

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

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

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

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

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

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

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

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

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

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

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

3. Each such utility shall make a triennial filing by March 31 of every third year, with such filings commencing for a Phase I Utility in 2020, and such filings commencing for a Phase II Utility in 2021, consisting of the schedules contained in the Commission's rules governing utility rate increase applications. Such filing shall encompass the three successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted, except that the filing for a Phase II Utility in 2021 shall encompass the four successive 12-month test periods ending December 31, 2020, and in every such case the filing for each year shall be identified separately and shall be segregated from any other year encompassed by the filing. If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or 9, any rate

adjustment clauses previously implemented related to facilities utilizing simple-cycle combustion turbines described in subdivision 6, shall be combined with the utility's costs, revenues and investments until the amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall combine such clauses with the utility's costs, revenues and investments only after it makes its initial determination with regard to necessary rate revisions or credits to customers' bills, and the amounts thereof, but after such clauses are combined as herein specified, they shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future triennial review proceedings. In a triennial filing under this subdivision that does not result in an overall rate change a utility may propose an adjustment to one or more tariffs that are revenue neutral to the utility.

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

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

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

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

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

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

~~revenue reductions related to energy efficiency programs. The Commission shall only allow such recovery to the extent that the Commission determines such revenue has not been recovered through margins from incremental off-system sales as defined in § 56-249.6 that are directly attributable to energy efficiency programs.~~

~~None of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, shall be assigned to any large general service customer. A large general service customer is a customer that has a verifiable history of having used more than 500 kilowatts of demand from a single meter of delivery. A utility shall not charge such large general service customer, as defined by the Commission, for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth;~~ *Energy efficiency pilot programs are in the public interest provided the pilot program is (i) of limited scope, cost, and duration and (ii) intended to determine whether a new or substantially revised program would be cost-effective.*

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

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

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

As used in this subdivision, "large general service customer" means a customer that has a verifiable history of having used more than one megawatt of demand from a single site. Large general service customers shall be exempt from requirements that they participate in energy efficiency programs if the Commission finds that the large general service customer has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with industry standards and other regulatory criteria stated in this section. The Commission shall, no later than June 30, 2021, adopt rules or regulations (i) establishing the process for large general service customers to apply for such an exemption, (ii) establishing the administrative procedures by which eligible customers will notify the utility, (iii) establishing an energy savings account where individual customer fees for efficiency are collected and earmarked for energy efficiency instead of allocated to the general rider for utility-administered programs, and (iv) defining the standard criteria that shall be satisfied by an applicant in order to notify the utility, including means of evaluation measurement and verification and confidentiality requirements. At a minimum, such rules and regulations shall require that each exempted large general service customer certify to the utility and Commission that its implemented energy efficiency programs have delivered measured and verified savings within the prior five years. A customer shall establish an account into which payments in lieu of *the energy efficiency rider shall be deposited for use by the customer in implementing energy efficiency measures at its facility. Any energy savings account shall allow year-to-year flexibility but should sunset on a rolling basis after five years, with funds unused for energy efficiency subject to forfeiture to the utility for use in support of other energy efficiency programs. In adopting such rules or regulations, the Commission shall also specify the timing as to when a utility shall accept and act on such notice, taking into consideration the utility's integrated resource planning process as well as its administration of energy efficiency programs that are approved for cost recovery by the Commission. Savings from large general service customers shall be accounted for in utility reporting in the standards in § 56-596.2.*

The notice of nonparticipation by a large general service customer shall be for the duration of the service life of the customer's energy efficiency measures. The Commission may on its own motion initiate steps necessary to verify such nonparticipant's achievement of energy efficiency if the Commission has a body of evidence that the non-participant has knowingly misrepresented its energy efficiency achievement. A utility shall not charge such large general service customer for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency, and environmental protection in the Commonwealth;

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

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

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

g. Reasonable administrative and operational costs, as reviewed and approved by the Commission, incurred to comply with percentage of income payment programs as established in § 63.2-806.

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

6. To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of (i) a coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or without the utility's service territory, (ii) one or more other generation facilities, (iii) one or more major unit modifications of generation facilities, including the costs of any system or equipment upgrade, system or equipment replacement, or other cost reasonably appropriate to extend the combined operating license for or the operating life of one or more generation facilities utilizing nuclear power, (iv) one or more new underground facilities to replace one or more existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth, (v) one or more pumped hydroelectricity generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or without the utility's service territory, or (vi) one or more electric distribution grid transformation projects; however, subject to the provisions of the following sentence, the utility shall not file a petition under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental increase in the level of investments associated with such a petition that exceeds five percent of such utility's distribution rate base, as such rate base was determined for the most recently ended 12-month test period in the utility's latest review proceeding conducted pursuant to subdivision 3 and concluded by

final order of the Commission prior to the date of filing of such petition under clause (iv). In all proceedings regarding petitions filed under clause (iv) or (vi), the level of investments approved for recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously approved for recovery in prior proceedings under clause (iv) or (vi), as applicable. As of December 1, 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs associated with conversions of overhead distribution facilities to underground facilities that have been previously approved or are pending approval by the Commission through a petition by the utility under this subdivision. Such a petition concerning facilities described in clause (ii) that utilize nuclear power, facilities described in clause (ii) that are coal-fueled and will be built by a Phase I Utility, or facilities described in clause (i) may also be filed before the expiration or termination of capped rates. A utility that constructs or makes modifications to any such facility, or purchases any facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, shall have the right to recover the costs of the facility, as accrued against income, through its rates, including projected construction work in progress, and any associated allowance for funds used during construction, planning, development and construction or acquisition costs, life-cycle costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs of infrastructure associated therewith, plus, as an incentive to undertake such projects, an enhanced rate of return on common equity calculated as specified below; however, in determining the amounts recoverable under a rate adjustment clause for new underground facilities, the Commission shall not consider, or increase or reduce such amounts recoverable because of (a) the operation and maintenance costs attributable to either the overhead distribution facilities being replaced or the new underground facilities or (b) any other costs attributable to the overhead distribution facilities being replaced. Notwithstanding the preceding sentence, the costs described in clauses (a) and (b) thereof shall remain eligible for recovery from customers through the utility's base rates for distribution service. A utility filing a petition for approval to construct or purchase a facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses may propose a rate adjustment clause based on a market index in lieu of a cost of service model for such facility. A utility seeking approval to construct or purchase a generating facility ~~described in clause (i) or (ii)~~ *that emits carbon dioxide* shall demonstrate that it has *already met the energy savings goals identified in § 56-596.2 and the identified need cannot be met more affordably through the deployment or utilization of demand-side resources or energy storage resources and that it has* considered and weighed alternative options, including third-party market alternatives, in its selection process. *In constructing any facility contemplated in subsection A of § 56-585.1:11, the utility shall (a) identify options for utilizing local workers; (b) identify the economic development benefits of the project for the Commonwealth, including capital investments and job creation; (c) consult with relevant governmental entities, including the Commonwealth's Chief Workforce Development Officer on opportunities to advance the Commonwealth's workforce and economic development goals, including furtherance of apprenticeship and other workforce training programs, and give priority to the hiring of local workers, including workers from historically economically disadvantaged communities. For the purposes of this subsection, "historically economically disadvantaged community" means a community that is (i) a community in which a majority of the population are people of color or (ii) a low-income geographic area. Relevant state agencies shall identify historically economically disadvantaged communities utilizing geographic information systems, U.S. Census tract demographic and poverty threshold data for the Commonwealth, and zip code areas.*

The costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities are classified by the utility as plant in service. *In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The Commission shall ensure that the development of new or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities or low-income geographic areas. The Commission may adopt any rules it deems necessary to determine the social cost of carbon.*

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

The conversion of any such facilities on or after September 1, 2016, is deemed to provide local and system-wide benefits and to be cost beneficial, and the costs associated with such new underground facilities are deemed to be reasonably and prudently incurred and, notwithstanding the provisions of subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision, provided that the total costs associated with the replacement of any subset of existing overhead distribution tap lines proposed by the utility with new underground facilities, exclusive of financing costs, shall not exceed an average cost per customer of $20,000, with such customers, including those served directly by or downline of the tap lines proposed for conversion, and, further, such total costs shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of $750,000. A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d. The Commission's final order regarding any such petition for approval of an electric distribution grid transformation plan shall be entered by the Commission not more than six months after the date of filing such petition. The Commission shall likewise enter its final order with respect to any petition by a utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived from sunlight, pursuant to subsection D of § 56-580, within six months after the date of filing such petition. The basis points to be added to the utility's general rate of return to calculate the enhanced rate of return on common equity, and the first portion of that facility's service life to which such enhanced rate of return shall be applied, shall vary by type of facility, as specified in the following table:

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

~~For generating facilities other than those utilizing nuclear power constructed pursuant to clause (ii) or those utilizing energy derived from offshore wind, as of July 1, 2013, only~~ *Only* those facilities as to which a rate adjustment clause under this subdivision has been previously approved by the Commission, or as to which a petition for approval of such rate adjustment clause was filed with the Commission, on or before January 1, ~~2013~~ *2019*, shall be entitled to the enhanced rate of return on common equity as specified in the above table during the construction phase of the facility and the approved first portion of its service life.

~~For generating facilities within the Commonwealth utilizing nuclear power or those utilizing energy derived from offshore wind projects located in waters off the Commonwealth's Atlantic shoreline, such facilities shall continue to be eligible for an enhanced rate of return on common equity during the construction phase of the facility and the approved first portion of its service life of between 12 and 25 years in the case of a facility utilizing nuclear power and for a service life of between 5 and 15 years in the case of a facility utilizing energy derived from offshore wind, provided, however, that, as of July 1, 2013, the enhanced return for such facilities constructed pursuant to clause (ii) shall be 100 basis points, which shall be added to the utility's general rate of return as determined under subdivision 2. Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014.~~ Thirty percent of all costs of ~~such~~ a facility utilizing energy derived from offshore wind that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014.

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

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

Construction, purchasing, or leasing activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from wind with an aggregate capacity of ~~5,000~~ *16,100* megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of ~~50~~ *100* megawatts, together with ~~a new test or demonstration project for~~ a utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than ~~16~~ *5000* megawatts, are in the public interest. To the extent that a utility elects to recover the costs of any such new generation facility or facilities through its rates for generation and distribution services and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (ii), the Commission shall, upon the request of the utility in a triennial review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding pursuant to subsection D of § 56-580 or in a triennial review proceeding.

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

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

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

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

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

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

7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and

records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs prudently incurred after the expiration or termination of capped rates related to other matters described in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped rates, provided, however, that no provision of this act shall affect the rights of any parties with respect to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset for regulatory accounting and ratemaking purposes under which it shall defer its operation and maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant and (ii) other work at such plant normally performed during a refueling outage. The utility shall amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning with the month in which such plant resumes operation after such refueling. The refueling cycle shall be the applicable period of time between planned refueling outages for such plant. As of January 1, 2014, such amortized costs are a component of base rates, recoverable in base rates only ratably over the refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with respect to triennial filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection B. This provision shall not be deemed to change or reset base rates.

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

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

specifically § 56-235.2, following the review of combined test period earnings of the utility in a triennial review, for normalization of nonrecurring test period costs and annualized adjustments for future costs, in determining any appropriate increase or decrease in the utility's rates for generation and distribution services pursuant to subdivision 8 a or 8 c.

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

a. The *revenue reductions related to energy efficiency measures or programs approved and deployed since the utility's previous triennial review have caused the utility, as verified by the Commission, during the test period or periods under review, considered as a whole, to earn more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates for generation and distribution services necessary to recover such revenue reductions. If the Commission finds, for reasons other than revenue reductions related to energy efficiency measures, that the* utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return, using the most recently ended 12-month test period as the basis for determining the amount of the rate increase necessary. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, the Commission may not order a rate increase, and in all triennial reviews of a Phase I or Phase II utility, the Commission may not order such rate increase unless it finds that the resulting rates are necessary to provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate increase under the standards of this sentence, and the amount thereof; and provided that, solely in connection with making its determination concerning the necessity for such a rate increase or the amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1, 2028, exclude from this most recently ended 12-month test period any remaining investment levels associated with a prior customer credit reinvestment offset pursuant to subdivision d.

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

c. In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after January 1, 2021, for a Phase II Utility in which the utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matter determined with respect to facilities described in subdivision 6, and the combined aggregate level of capital investment that the

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

d. (Expires July 1, 2028) In any triennial review proceeding conducted after December 31, 2017, upon the request of the utility, the Commission shall determine, prior to directing that 70 percent of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the test period or periods under review be credited to customer bills pursuant to subdivision 8 b, the aggregate level of prior capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test period or periods under review in both (i) new utility-owned generation facilities utilizing energy derived from sunlight, or from onshore or offshore wind, and (ii) electric distribution grid transformation projects, as determined by the utility's plant in service and construction work in progress balances related to such investments as recorded per books by the utility for financial reporting purposes as of the end of the most recent test period under review. Any such combined capital investment amounts shall offset any customer bill credit amounts, on a dollar for dollar basis, up to the aggregate level of invested or committed capital under clauses (i) and (ii). The aggregate level of qualifying invested or committed capital under clauses (i) and (ii) is referred to in this subdivision as the customer credit reinvestment offset, which offsets the customer bill credit amount that the utility has invested or will invest in new solar or wind generation facilities or electric distribution grid transformation projects for the benefit of customers, in amounts up to 100 percent of earnings that are more than 70 basis points above the utility's fair rate of return on its generation and distribution services, and thereby reduce or eliminate otherwise incremental rate adjustment clause charges and increases to customer bills, which is deemed to be in the public interest. If 100 percent of the amount of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services, as determined in subdivision 2, exceeds the aggregate level of invested capital in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and electric distribution grid transformation projects, as provided in clauses (i) and (ii), during the test period or periods under review, then 70 percent of the amount of such excess shall be credited to customer bills as provided in subdivision 8 b in connection with the triennial review proceeding. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is the subject of any customer credit reinvestment offset pursuant to this subdivision shall not thereafter be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall not thereafter be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 and shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is not the subject of any customer credit reinvestment offset pursuant to this subdivision may be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 until such costs are fully recovered, and if such costs are recovered through the utility's rates for generation and distribution services, they shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. Only the portion of such costs of new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that has not been included in any customer credit reinvestment offset pursuant to this subdivision, and not otherwise recovered through the utility's rates for generation and distribution services, may be the subject of a rate adjustment clause petition by the utility pursuant to subdivision 6.

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

9. If, as a result of a triennial review required under this subsection and conducted with respect to any test period or periods under review ending later than December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, under review ending later than December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), the Commission finds, with respect to such test period or periods considered as a whole, that (i) any utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, and (ii) the total aggregate regulated rates of such utility at the end of the most recently ended 12-month test period exceeded the annual increases in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, compounded annually, when compared to the total aggregate regulated rates of such utility as determined pursuant to the review conducted for the base period, the Commission shall, unless it finds that such action is not in the public interest or that the provisions of subdivisions 8 b and c are more consistent with the public interest, direct that any or all earnings for such test period or periods under review, considered as a whole that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points, above such fair combined rate of return shall be credited to customers' bills, in lieu of the provisions of subdivisions 8 b and c, provided that no credits shall be provided pursuant to this subdivision in connection with any triennial review unless such bill credits would be payable pursuant to the provisions of subdivision 8 d, and any credits under this subdivision shall be calculated net of any customer credit reinvestment offset amounts under subdivision 8 d. Any such credits shall be amortized and allocated among customer classes in the manner provided by subdivision 8 b. For purposes of this subdivision:

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

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

10. For purposes of this section, the Commission shall regulate the rates, terms and conditions of any utility subject to this section on a stand-alone basis utilizing the actual end-of-test period capital structure and cost of capital of such utility, excluding any debt associated with securitized bonds that are the obligation of non-Virginia jurisdictional customers, unless the Commission finds that the debt to equity ratio of such capital structure is unreasonable for such utility, in which case the Commission may utilize a debt to equity ratio that it finds to be reasonable for such utility in determining any rate adjustment pursuant to subdivisions 8 a and c, and without regard to the cost of capital, capital structure, revenues, expenses or investments of any other entity with which such utility may be affiliated. In particular, and without limitation, the Commission shall determine the federal and state income tax costs for any such utility that is part of a publicly traded, consolidated group as follows: (i) such utility's

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apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.

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

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

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

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

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

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

B. 1. Pursuant to subsection A, construction by a Phase II Utility, as defined in subdivision A 1 of § 56-585.1, of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline, with an aggregate rated capacity of not less than 2,500 megawatts and not more than 3,000 megawatts, along with electrical transmission or distribution facilities associated therewith for interconnection is in the public interest. In acting upon any request for cost recovery by a Phase II Utility for costs associated with such a facility, the Commission shall determine the reasonableness and prudence of any such costs, provided that such costs shall be presumed to be reasonably and prudently incurred if the Commission determines that (i) the utility has complied with the competitive solicitation and procurement requirements pursuant to subsection D; (ii) the project's projected total levelized cost of energy, including any tax credit, on a cost per megawatt basis inclusive of the costs of transmission and distribution facilities associated with the facility's connection, does not exceed 1.6 times the comparable cost, on an unweighted average basis, of a conventional simple cycle combustion turbine generating facility as most recently estimated by the U.S. Energy Information Administration in its Annual Outlook at the time of the utility's initial cost recovery request; and (iii) the utility has commenced construction of such facilities for U.S. income taxation purposes prior to January 1, 2024, or has a plan for any such facility to be in service prior to January 1, 2028. The Commission shall disallow any costs, or any portion thereof, only if they are otherwise unreasonably and imprudently incurred. In its review, the Commission shall give great weight to the public interest determination in this subsection.

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

2. Any such costs proposed for recovery through a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 shall be allocated to all customers of the utility, other than low-income residential customers, in the Commonwealth as a non-bypassable charge, irrespective of the generation supplier of any such customer. No electric cooperative customer of the utility shall be assigned, nor shall the utility collect from any such cooperative, any of the costs of such facilities, including electrical transmission or distribution facilities associated therewith for interconnection. The Commission may promulgate such *rules, regulations, or other directives necessary to administer the eligibility for this exemption.*

3. For purposes of this subsection, (i) "low-income residential customer" includes any residential customer household of a Phase II Utility where the customer or a dependent is a recipient of a state-funded or federally funded public assistance program for the indigent and requests exemption from the utility from such charges and (ii) "aggregate load" means the combined electrical load associated with selected non-residential customer accounts with the same entity name or in the name of affiliated entities under a common parent company.

C. In constructing any such facility described in subsection A, the utility shall (i) identify options for utilizing local workers; (ii) identify the economic development benefits of the project for the Commonwealth, including capital investments and job creation; (iii) consult with relevant governmental entities, including the Commonwealth's Chief Workforce Development Officer and the Virginia Economic Development Partnership, on opportunities to advance the Commonwealth's workforce and economic development goals, including furtherance of apprenticeship and other workforce training programs; and (iv) give priority to the hiring of local workers, including workers from historically economically disadvantaged communities. For the purposes of this subsection, "historically economically disadvantaged community" means a community that is (i) a community in which a majority of the population are people of color or (ii) a low-income geographic area. Relevant state agencies shall identify historically economically disadvantaged communities utilizing geographic information systems, U.S. Census tract demographic and poverty threshold data for the Commonwealth, and zip code areas.

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

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

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

A. As used in this section:

"Low-income qualifying projects" means a project that serves a low-income customer, as that term is defined in § 56-594.

"Previously developed project site" means any property, including related buffer areas, if any, that has been previously disturbed or developed for non-single-family residential, non-agricultural, or non-silvicultural use, regardless of whether such property currently is being used for any purpose. "Previously developed project site" includes a brownfield as defined in § 10.1-1230 or any parcel that has been previously used (i) for a retail, commercial, or industrial purpose; (ii) as a parking lot; (iii) as the site of a parking lot canopy or structure; (iv) for mining or quarrying; or (v) as a landfill.

"Retail suppliers" shall include a Phase I or Phase II Utility, as those terms are defined in subdivision A 1 of § 56-585.1, as well as other electric energy suppliers as defined by § 56-576.

"Total electric energy" means total electric energy sold to a Virginia jurisdictional retail customer by an incumbent electric utility or other retail supplier of electric energy in the previous calendar year, excluding an amount equivalent to the annual percentages of the electric energy that was suppled to such customer from nuclear generating plants located within the Commonwealth in the previous calendar year, provided such nuclear units were operating by July 1, 2020.

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

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

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

3. By December 31, 2030, any Phase II Utility shall retire any coal-fired electric generating units located in the coalfield region of the Commonwealth that co-fires with biomass, unless such facility can demonstrate at least 83 percent reduction in carbon emissions through capture and sequestration.

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

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

C. Each retail supplier of electric energy in the Commonwealth shall participate in a renewable energy portfolio standard program ("RPS Program") that establishes annual goals for the sale of renewable energy to retail customers. To comply with the RPS program, every retail supplier of electricity shall procure Renewable Energy Certificates ("RECs") originating from renewable energy standard eligible sources ("RPS eligible sources"). For purposes of complying with the RPS Program, from 2021 to 2024, a retail supplier may use RECs from any renewable energy facility, as defined in § 56-576. However, at no time during this period or thereafter may any retail supplier use RECs from (i) renewable thermal energy facilities, (ii) renewable thermal energy equivalent facilities, (iii) biomass-fired facilities that are outside the Commonwealth, or (iv) biomass-fired facilities operating in the Commonwealth as of January 1, 2020, that supply 10 percent or more of their annual net electrical generation to the electric grid or more than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected. From compliance year 2025 and all years after, retail suppliers may only use RECs from RPS eligible sources for compliance with the RPS Program.

In order to qualify as RPS eligible sources for retail suppliers, such sources must be (i) electric-generating resources that generate electric energy derived from solar, wind, or falling water, provided such resources are located in the Commonwealth or are physically located within the PJM Interconnection, LLC ("PJM") region; (ii) waste-to-energy or landfill gas-fired generating resources located in the Commonwealth and in operation as of January 1, 2020, provided such resources do not use forest or woody biomass as fuel; (iii) non-utility-owned resources from falling water that (a) are less than 654 megawatts, (b) began commercial operation after December 31, 1979, or (c) added incremental generation representing greater than 50 percent of the original nameplate capacity after December 31, 1979; or (iv) are biomass-fired facilities in operation in the Commonwealth in operation as of January 1, 2020, that supply no more than 10 percent of their annual net electrical generation to the electric grid or no more than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected. The total amount of renewable energy credits that may be sold by any RPS eligible source using biomass in any calendar year shall be no more than the number of megawatt hours of electricity produced by that facility in calendar year 2019. Any biomass-fired facility qualifying as an RPS eligible source shall cease to qualify as an RPS eligible source if it undertakes any maintenance, refurbishment, or other type of project that increases its annual output by more than five percent. In order to comply with the RPS program, each Phase I and Phase II Utility may use and retire the environmental attributes associated with any existing owned or contracted solar, wind, or falling water electric generating resources in operation, or proposed for operation, in the Commonwealth or physically located within the PJM region, with such resource qualifying as a Commonwealth-located resource for purposes of this subdivision, as of January 1, 2020, provided such renewable attributes are verified as RECs consistent with the PJM-EIS Generation Attribute Tracking System.

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

Phase I Utilities and Other Retail Suppliers Operating in the Service Territory of a Phase I Utility		*Phase II Utilities and Other Retail Suppliers Operating in the Service Territory of a Phase II Utility*	
Year	*RPS Program Requirement*	*Year*	*RPS Program Requirement*
2021	*6%*	*2021*	*14%*
2022	*7%*	*2022*	*17%*
2023	*8%*	*2023*	*20%*
2024	*10%*	*2024*	*23%*
2025	*14%*	*2025*	*26%*
2026	*17%*	*2026*	*29%*
2027	*20%*	*2027*	*32%*
2028	*24%*	*2028*	*35%*
2029	*27%*	*2029*	*38%*
2030	*30%*	*2030*	*41%*
2031	*33%*	*2031*	*45%*

2032	*36%*	*2032*	*49%*
2033	*39%*	*2033*	*52%*
2034	*42%*	*2034*	*55%*
2035	*45%*	*2035*	*59%*
2036	*53%*	*2036*	*63%*
2037	*53%*	*2037*	*67%*
2038	*57%*	*2038*	*71%*
2039	*61%*	*2039*	*75%*
2040	*65%*	*2040*	*79%*
2041	*68%*	*2041*	*83%*
2042	*71%*	*2042*	*87%*
2043	*74%*	*2043*	*91%*
2044	*100%*	*2044*	*95%*
2045	*80%*	*2045 and thereafter*	*100%*
2046	*84%*		
2047	*88%*		
2048	*92%*		
2049	*96%*		
2050 and thereafter	*100%*		

Retail suppliers, except for a Phase I Utility, shall meet one percent of the RPS Program requirement in any given compliance year with solar, wind, or anaerobic digestion resources of one megawatt or less located in the Commonwealth, with no less than 25 percent of such one percent composed of low-income qualifying projects.

Beginning with the 2025 compliance year and thereafter, at least 75 percent of all RECs used by a retail supplier, except for a Phase I Utility, in a compliance period shall come from resources located in Virginia.

A retail supplier of electricity may apply renewable energy sales achieved or RECs acquired in excess of the sales requirement for that RPS Program to the sales requirements for future RPS Program requirements in the year in which it was generated and the five calendar years after the renewable energy was generated or the RECs were created. To the extent a retail supplier of electricity is a Phase I or Phase II Utility that procures RECs for RPS Program compliance from resources the utility does not own, the utility shall be entitled to recover the costs of such certificates, at its election pursuant to § 56-249.6 or subdivision A 5 d of § 56-585.1. A retail supplier of electricity other than a Phase I or Phase II Utility may only use RECs from facilities that produce electricity via falling water equal to or less than 2.9 percent of their total electric energy sold in each year from 2021 through 2035, equal to or less than 3.5 percent of their total electric energy sold in each year from 2036 through 2042 and equal to or less than four percent of their total electric energy sold in each year from 2043 through 2050, and shall not exceed these amounts to comply with the RPS Program requirements. The limitations in this subsection shall apply only to facilities that produce electricity via falling water that is less than 65 megawatts, or that began commercial operation or added incremental generation representing the majority of nameplate capacity after December 31, 1979.

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

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

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

b. By December 31, 2027, each Phase I Utility shall construct or acquire at least 200 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and approximately 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

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

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

2. By December 31, 2035, each Phase II Utility shall construct or acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of, 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, which shall include 1,100 megawatts of solar generation of a nameplate capacity not to exceed three megawatts per individual project. At least 200 megawatts of the 16,100 megawatts shall be placed on previously developed project sites.

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

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

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

d. By December 31, 2035, each Phase II Utility shall construct or acquire at least 7,300 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and approximately 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being form construction or acquisition by such Phase II Utility.

e. Nothing in this subdivision 2 shall prohibit such Phase II Utility from construction or acquiring, or entering into agreements to purchase the energy, capacity, and environmental attributes of more than 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

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

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

4. In connection with the requirements of this subsection, each Phase I and Phase II Utility shall, commencing in 2020 and concluding in 2030, submit annually a plan and petition for approval for the development of new solar and onshore wind generation capacity. Such plan shall reflect, in the aggregate and over its duration, the requirements of subdivision D concerning the allocation percentages for construction or purchase of such capacity. Such petition may contain a request for approval to construct such facilities pursuant to subsection D of § 56-580 and a request for approval or update of a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 to recover the costs of such facilities. Such plan shall also include the utility's plan to meet the energy storage project targets of subdivision E, including the goal of installing at least 10 percent of such energy storage projects behind the meter. Notwithstanding any other provision of this title, the Commission's final order regarding any such petition and associated requests shall be entered by the Commission not more than six months after the date of the filing of such petition.

5. If, in any year, a retail supplier of electricity is unable to meet the compliance obligation of the RPS Program requirements or if the cost of RECs necessary to comply with RPS Program requirements exceeds $45 per megawatt hour, such supplier shall be obligated to make a deficiency payment equal to $45 for each megawatt-hour shortfall for the year of noncompliance, except that the deficiency payment for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in the Commonwealth shall be $75 per megawatts hour for resources one megawatt and lower. The amount of any deficiency payment shall increase by one percent annually after 2021. A Phase I or Phase II Utility shall be entitled to recover the costs of such payments as a cost of compliance with the requirements of this subsection pursuant to subdivision A 5 d of § 56-585.1. All proceeds from the deficiency payments shall be deposited into an interest-bearing account administered by the Department of Mines, Minerals and Energy. In administering this account, the Department of Mines, Minerals and Energy shall manage the account as follows: (i) 50 percent of total revenue shall be directed to job training programs in historically economically disadvantaged communities; (ii) 16 percent of total revenue shall be directed to energy efficiency measures for public facilities; (iii) 30 percent of total revenue shall be directed to renewable energy programs located in historically economically disadvantaged communities; and (iv) four percent of total revenue shall be directed to administrative costs.

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

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

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

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

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

5. Approximately 35 percent of the energy storage projects shall be owned and operated by third parties. By January 1, 2021, the Commission shall adopt regulations to achieve the deployment of *energy storage for the Commonwealth required in subdivisions E 1 and E 2, including regulations that set interim targets and update existing utility planning and procurement rules. The regulations shall include programs and mechanisms to deploy energy storage, including competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs.*

F. Nothing in this section shall apply to any entity organized under Chapter 9 (§ 56-231.15 et seq.).

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

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

A. The Commission shall set the rate of a non-bypassable universal service fee to fund the Percentage of Income Payment Program established pursuant to § 63.2-806. Such universal service fee shall be allocated to retail electric customers on the basis of the amount of kilowatt-hours used.

B. An investor-owned electric utility shall collect such universal service fee and remit such funds to the Percentage of Income Payment Fund established pursuant to § 63.2-806.

C. The Commission shall assist the Department of Housing and Community Development (the Department) in the administration of the Percentage of Income Payment Program as requested by the Department.

§ 56-594. Net energy metering provisions.

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

B. For the purpose of this section:

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

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

"Low-income customer" means a person or household that is an existing participant or eligible to participate in any of the following programs: the Home Energy Assistance Program, the state plan for medical assistance, the Supplemental Nutrition Assistance Program, the Special Supplemental Nutrition Program for Women, Infants, and Children, the Housing Choice Voucher Program, the Family Access to Medical Insurance Security Plan, or Temporary Assistance for Needy Families.

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

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

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

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

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

E. If electricity generated by an eligible customer-generator or eligible agricultural customer-generator over the net metering period exceeds the electricity consumed by the eligible customer-generator or eligible agricultural customer-generator, the customer-generator or eligible agricultural customer-generator shall be compensated for the excess electricity if the entity contracting to receive such electric energy and the eligible customer-generator or eligible agricultural customer-generator enter into a power purchase agreement for such excess electricity. Upon the written request of the eligible customer-generator or eligible agricultural customer-generator, the supplier that serves the eligible customer-generator or eligible agricultural customer-generator shall enter into a power purchase agreement with the requesting eligible customer-generator or eligible agricultural customer-generator that is consistent with the minimum requirements for contracts established by the Commission pursuant to subsection D. The power purchase agreement shall obligate the supplier to purchase such excess electricity at the rate that is provided for such purchases in a net metering standard contract or tariff approved by the Commission, unless the parties agree to a higher rate. The eligible customer-generator or eligible agricultural customer-generator owns any renewable energy certificates associated with its electrical generating facility; however, at the time that the eligible customer-generator or eligible agricultural customer-generator enters into a power purchase agreement with its supplier, the eligible customer-generator or eligible agricultural customer-generator shall have a one-time option to sell the renewable energy certificates associated with such electrical generating facility to its supplier and be compensated at an amount that is established by the Commission to reflect the value of such renewable energy certificates. Nothing in this section shall prevent the eligible customer-generator or eligible agricultural customer-generator and the supplier from voluntarily entering into an agreement for the sale and purchase of excess electricity or renewable energy certificates at mutually-agreed upon prices if the eligible customer-generator or eligible agricultural customer-generator does not exercise its option to sell its renewable energy certificates to its supplier at Commission-approved prices at the time that the eligible customer-generator or eligible agricultural customer-generator enters into a power purchase agreement with its supplier. All costs incurred by the supplier to purchase excess electricity and renewable energy certificates from eligible customer-generators or eligible agricultural customer-generators shall be recoverable through its Renewable Energy Portfolio Standard (RPS) rate adjustment clause, if the supplier has a Commission-approved RPS plan. If not, then all costs shall be recoverable through the supplier's fuel adjustment clause. For purposes of this section, "all costs" shall be defined as the rates paid to the eligible customer-generator or eligible agricultural customer-generator for the purchase of excess electricity and renewable energy certificates and any administrative costs incurred to manage the eligible customer-generator's or eligible agricultural customer-generator's power purchase arrangements. The net metering standard contract or tariff shall be available to eligible customer-generators or eligible agricultural customer-generators on a first-come, first-served basis in each electric distribution company's Virginia service area until the rated generating capacity owned and operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators in the Commonwealth reaches ~~one~~ *six* percent, *in the aggregate, five percent of which is available to all customers and one percent of which is available only to low-income customers* of each electric distribution company's adjusted Virginia peak-load forecast for the previous year ~~(the systemwide cap)~~, and shall require the supplier to pay the eligible customer-generator or eligible agricultural customer-generator for such excess electricity in a timely manner at a rate to be established by the Commission.

On and after the earlier of (i) 2024 for a Phase I Utility or 2025 for a Phase II Utility or (ii) when the aggregate rated generating capacity owned and operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural generators in the Commonwealth reaches 3 percent of a Phase I or Phase II Utility's adjusted Virginia peak-load forecast for the previous year, the Commission shall conduct a net energy metering proceeding.

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

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

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

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

I. When any electric utility notifies the Commission that it has received sufficient applications to satisfy 60 percent of available nameplate capacity under the net metering program, the Commission shall open a generic docket to:

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

2. Establish an appropriate netting measurement interval for a successor tariff that is just and reasonable in light of the costs and benefits of the net metering program in aggregate, and applicable to new requests for net energy metering service submitted after the limit in § 56-594 is reached; and

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

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

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

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

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

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

§ 56-596.2. Energy efficiency programs; financial assistance for low-income customers; Percentage of Income Payment Plan weatherization program.

A. For purposes of this section, "net annual savings" means (i) the total combined energy savings achieved by deployed energy efficiency and demand response measures, net of free rider savings from customers who would have implemented a measure in absence of utility-delivered energy efficiency programs and net of spillover savings from customers who implement an efficiency measure not directly targeted by utility-delivered energy efficiency programs and (ii) savings attributable to newly installed combined heat and power facilities, including waste heat-to-power facilities, either as a demand-side energy efficiency measure or a supply-side generation alternative, including any associated reduction in transmission line losses, provided that biomass is not a fuel and the total efficiency, including the use of thermal energy, for eligible combined heat and power facilities must meet or exceed 65 percent and have a nameplate capacity rating of less than 25 megawatts.

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

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

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

C. Notwithstanding any other provision of law, each investor-owned incumbent electric utility shall implement energy efficiency programs and measures to achieve the following annual energy efficiency savings, as measured by the total combined kilowatt-hour savings achieved by deployed efficiency and demand response measures:

1. For Phase I electric utilities:

a. In calendar year 2022, at least 0.25 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

b. In calendar year 2023, at least 0.50 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

c. In calendar year 2024, at least 0.75 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

d. In calendar year 2025, at least 2.00 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

2. For Phase II electric utilities:

a. In calendar year 2022, at least 0.25 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

b. In calendar year 2023, at least 0.75 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

c. In calendar year 2024, at least 1.75 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time;

d. In calendar year 2025, at least 5.0 percent of the average annual energy jurisdictional retail sales by that utility in 2019, adjusted for any supply service customer loss since that time.

3. Beginning in 2026, and every three years thereafter, in each utility's annual energy efficiency rate adjustment clause proceeding the Commission shall adjust the utility's required energy efficiency savings goals for the successive three-year period. As part of such proceeding, the Commission may consider the feasibility of achieving energy efficiency goals and future energy efficiency savings through cost-effective programs and measures.

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

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

§ 63.2-806. Percentage of Income Payment Program and Fund; report; survey.

A. The General Assembly declares that it is the policy of the Commonwealth to ensure that the residential energy burden on low-income families is affordable and sustainable and to educate such families about energy conservation. To this end, the Percentage of Income Payment Program (PIPP) is hereby created, and the Department of Housing and Community Development is designated as the state agency responsible for administering such program.

B. The monthly electric utility payment of any person participating in PIPP shall be capped at six percent, or, if the participant's home uses electric heat, 10 percent, of the participant's household income. A participant may further reduce his monthly electric utility payment through a conservation *program incentive. Under this program incentive, if a participant lowers his monthly electricity usage below his historical baseline average, the participant's electric utility bill for such month shall be reduced by 50 percent of the monetary amount by which such participant lowered his usage.*

After a person participates in PIPP for 12 months, the electric utility provider shall transition the participant to a budget billing system if such transition would lower such participant's monthly electric utility payment. If transition to a budget billing system would not lower the participant's monthly electric utility payment, a comprehensive audit shall be conducted on the participant's home to identify energy inefficiencies, and the participant's home shall be retrofitted with any energy-saving equipment or measures necessary to ensure that the participant's energy burden is affordable and sustainable. Participants who transition to a budget billing system in accordance with this subsection shall be forgiven of any arrearages on electric utility bills accrued prior to participation in PIPP upon making timely and full PIPP payments to the electric utility provider for 12 consecutive months; all other PIPP participants shall be forgiven of arrearages accrued prior to participation in PIPP after making timely and full PIPP payments to the electric utility provider for 12 consecutive months.

C. A person shall be eligible to participate in PIPP if:

1. Such person or his household is an existing participant or is eligible to participate in any of the following: the Home Energy Assistance Program, the state plan for medical assistance, the Supplemental Nutrition Assistance Program, the Special Supplemental Nutrition Program for Women, Infants, and Children, the Housing Choice Voucher Program, the Family Access to Medical Insurance Security Plan, or Temporary Assistance for Needy Families; and

2. Such person (i) participates in an energy efficiency and weatherization program established by regulations of the Department of Housing and Community Development, which shall include an annual audit of energy usage; (ii) complies with any energy education and training requirements set forth in regulations of the Department of Housing and Community Development, including annual energy usage and behavioral assessments; and (iii) agrees to any data access and sharing policies necessary to provide the Department of Housing and Community Development with information regarding the applicant's energy usage and payment activities with the electric utility provider both at the time of application and throughout his participation in PIPP.

D. There is hereby created in the state treasury a special nonreverting fund to be known as the Percentage of Income Payment Fund, hereinafter "the Fund." Moneys in the Fund shall be used to:

1. Pay to electric utility providers the monthly account balances of PIPP participants that remain after such participants' percentage-of-income payment less any earned conservation program incentive deductions; and

2. Fund the energy efficiency, weatherization, and educational and training programs and initiatives established by the Department of Housing and Community Development for the implementation of PIPP.

The Fund shall be established on the books of the Comptroller. The Fund shall consist of moneys contributed by electric utility providers collected through a non-bypassable universal service fee pursuant to § 56-585.5. Interest earned on moneys in the Fund shall remain in the Fund and be credited to it. Any moneys remaining in the Fund, including interest thereon, at the end of each fiscal year shall not revert to the general fund but shall remain in the Fund. Moneys in the Fund shall be used solely for the purposes set forth in this section. The State Treasurer shall make expenditures and disbursements from the Fund on warrants issued by the Comptroller upon written request signed by the Director of the Department of Housing and Community Development. Up to 12 percent of the Fund may be used to pay the Department of Housing and Community Development's expenses in administering PIPP.

E. In administering PIPP, it shall be the responsibility of the Department of Housing and Community Development to:

1. Administer distributions from the Fund;

2. Lead and facilitate meetings with electric utility providers for the purpose of sharing information and implementing the program;

3. Collect and analyze data regarding the amounts of energy assistance provided through PIPP;

4. Develop and maintain a statewide list of available private and governmental resources for low-income Virginians in need of energy assistance; and

5. Report annually to the Governor and the General Assembly on or before October 1 of each year on the effectiveness of PIPP in meeting the energy needs of low-income Virginians. In preparing the report, the Department shall:

a. Conduct a survey each year that collects information regarding the extent to which the Commonwealth's PIPP efforts are adequate and are not duplicative of similar services provided by utility services providers, charitable organizations, or local governments;

b. Obtain information on energy programs in other states; and

c. Obtain any information necessary to complete the required annual survey and report.

F. Actions of the Department relating to the review, allocation, and awarding of benefits and grants *shall be exempt from the provisions of Articles 3 (§ 2.2-4018 et seq.) and 4 (§ 2.2-4024 et seq.) of the Administrative Process Act.*

G. No employee or former employee of the Department of Housing and Community Development shall divulge any information acquired by him in the performance of his duties with respect to the income or assistance eligibility of any individual or household obtained in the course of administering PIPP, except in accordance with a proper judicial order. The provisions of this subsection shall not apply to (i) acts performed or words spoken or published in the line of duty under law; (ii) inquiries and investigations to obtain information as to the implementation of this section by a duly constituted committee of the General Assembly, or when such inquiry or investigation is relevant to its study, provided that any such information shall be privileged; or (iii) the publication of statistics so classified as to prevent the identification of any individual or household.

H. This section shall not apply to any entity organized pursuant to Chapter 9.1 of Title 56.

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

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

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

b. The aggregated capacity of all generation facilities that are subject to such third party power purchase agreements at any time during the pilot program shall not *exceed 1000* megawatts for an investor-owned utility that was bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, or ~~seven~~ *30* megawatts for an investor-owned utility that was not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002. Such limitation on the aggregated capacity of such facilities shall constitute a portion of the existing limit of ~~one~~ *six* percent of each Pilot Utility's adjusted Virginia peak-load forecast for the previous year that is available to eligible customer-generators pursuant to subsection E of § 56-594 of the Code of Virginia. Notwithstanding any provision of this act that incorporates provisions of § 56-594, the seller and the customer shall elect either to (i) enter into their third party power purchase agreement subject to the conditions and provisions of the Pilot Utility's net energy metering program under § 56-594 or (ii) provide that electricity generated from the generation facilities subject to the third party power purchase agreement will not be net metered under § 56-594, provided that an election not to net meter under § 56-594 shall not exempt the third party power purchase agreement and the parties thereto from the requirements of this act that incorporate provisions of § 56-594;

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

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

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

(iii) of such subsection;

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

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

3. That §§ 56-585.1:2 and 56-585.2 of the Code of Virginia are repealed.

4. That any moneys in the Virginia Shoreline Resiliency Fund, as created by Chapter 762 of the Acts of Assembly of 2016, shall remain in the Virginia Community Flood Preparedness Fund pursuant to § 10.1-603.25 of the Code of Virginia, as amended by this act.

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

6. That the Department of Mines, Minerals and Energy, in consultation with the Council on Environmental Justice and appropriate stakeholders, shall report to the House and Committee on Labor and Commerce and the Senate Committee on Commerce and Labor and to the Council on Environmental Justice that ensures that the implementation of this act does not impose a disproportionate burden on minority or historically disadvantaged communities.

7. That in developing a plan to reduce carbon dioxide emissions from covered units described in § 10.1-1308 of the Code of Virginia, the Secretary of Natural Resources and the Secretary of Commerce and Trade, in consultation with the State Corporation Commission and the Council on Environmental Justice and appropriate stakeholders, shall report to the General Assembly by January 1, 2022, any recommendations on how to achieve 100 percent carbon free electric energy generation by 2050 at least cost for ratepayers. Such report shall include a recommendation on whether the General Assembly should permanently repeal the ability to obtain a certificate of public convenience and necessity for any electric generating unit that emits carbon as a byproduct of combusting fuel to generate electricity. Until the General Assembly receives such report, the Commission shall not issue a certificate for public convenience and necessity for any investor-owned utility to own, operate, or construct any electric generating unit that emits carbon as a byproduct of combusting fuel to generate electricity.

8. That it shall be the policy of the Commonwealth that the State Corporation Commission, Department of Environmental Quality, Department of Mines, Minerals and Energy, Virginia Council on Environmental Justice, and other applicable state agencies, in the development of energy programs, job training programs, and placement of renewable energy facilities, shall consider those facilities and programs being to the benefit of local workers, low-income geographic areas and historically economically disadvantaged communities that are located near previously and presently permitted fossil fuel facilities or coal mines.

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

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

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

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

13. That by January 1, 2028, if the Secretary of Natural Resources and the Secretary of Commerce and Trade determine that the greenhouse gas reduction targets are not met pursuant to § 10.1-1330, then there shall be a moratorium on the issuance of permits for new fossil fuel fired generating facilities by January 1, 2030.

HOUSE SUBSTITUTE

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