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SENATE BILL NO. 851

Offered January 8, 2020
Prefiled January 8, 2020

A BILL to amend and reenact §§ 10.1-1308, 56-576, 56-577, 56-585.1, 56-585.2, 56-594, and 56-596.2 of the Code of Virginia; to amend the Code of Virginia by adding a section numbered 56-585.1:11; and to repeal Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, and the eleventh enactment of Chapter 296 of the Acts of Assembly of 2018, 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.

Patrons—McClellan, Edwards, Marsden, Boysko, Ebbin, Favola, Hashmi and Lewis

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Referred to Committee on Commerce and Labor

Be it enacted by the General Assembly of Virginia:

1. That §§ 10.1-1308, 56-576, 56-577, 56-585.1, 56-585.2, 56-594, and 56-596.2 of the Code of Virginia are amended and reenacted and that the Code of Virginia is amended by adding a section numbered 56-585.1:11 as follows:

§ 10.1-1308. Regulations.

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

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

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

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

E. Notwithstanding any other provision of law, the Board shall adopt regulations establishing a carbon dioxide cap and trade program to limit and reduce the total carbon dioxide emissions released by electric generation facilities. The regulations shall comply with the Regional Greenhouse Gas Initiative (RGGI) model rule and shall specify that the Department 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.

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 subsection. 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 section and (ii) use the proceeds without further appropriation for programs promulgated through the Administrative Process Act (§ 2.2-4000 et seq.), for the following purposes, with oversight from the Department with the approval of the Secretary:

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1. Fifty percent of total revenues shall be directed to the Department of Mines, Minerals and Energy for low-income, disability, veteran, and age-qualifying energy efficiency programs, even if such programs are administered by other agencies;

2. Sixteen percent shall be directed to the Department of Mines, Minerals and Energy for additional energy efficiency measures on state and locally owned property;

3. Thirty percent shall be directed to the Department of Conservation and Recreation for local government-led coastal resiliency efforts; and

4. Four percent shall be directed to administrative costs.

In the expenditure of funds, all efforts shall be made to utilize existing established funds and programs. No money shall be expended without the rules and regulations for such expenditure being subject to the Administrative Process Act (§ 2.2-4000 et seq.).

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

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

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

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.

"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.

"Incremental net annual savings" means the total combined kilowatt-hour savings achieved by deployed energy efficiency and demand response measures in their first year, net of (i) free rider savings from customers who would have implemented a measure or measures in absence of utility-delivered energy efficiency programs and (ii) spillover savings from customers who implement an efficiency measure or measures not directly targeted by utility-delivered energy efficiency programs.

"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

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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 would be cost-effective, provided that the costs of any such approved pilot project shall not count toward the aggregate amount of projected costs of programs as set forth in § 56-596.2*.

"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.

§ 56-577. Schedule for transition to retail competition; Commission authority; exemptions; pilot programs.

A. Retail competition for the purchase and sale of electric energy shall be subject to the following provisions:

1. Each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which entity may be an independent system operator, to which such utility shall transfer the management and control of its transmission system, subject to the provisions of § 56-579.

2. The generation of electric energy shall be subject to regulation as specified in this chapter.

3. Subject to the provisions of subdivisions 4 and 5, only individual retail customers of electric energy within the Commonwealth, regardless of customer class, whose demand during the most recent calendar year exceeded five megawatts but did not exceed one percent of the customer's incumbent electric utility's peak load during the most recent calendar year unless such customer had noncoincident peak demand in excess of 90 megawatts in calendar year 2006 or any year thereafter, shall be permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth, except for any incumbent electric utility other than the incumbent electric utility serving the exclusive service territory in which such a customer is located, subject to the following conditions:

a. If such customer does not purchase electric energy from licensed suppliers, such customer shall purchase electric energy from its incumbent electric utility.

b. Except as provided in subdivision 4, the demands of individual retail customers may not be aggregated or combined for the purpose of meeting the demand limitations of this provision, any other provision of this chapter to the contrary notwithstanding. For the purposes of this section, each noncontiguous site will nevertheless constitute an individual retail customer even though one or more such sites may be under common ownership of a single person.

c. If such customer does purchase electric energy from licensed suppliers after the expiration or termination of capped rates, it shall not thereafter be entitled to purchase electric energy from the incumbent electric utility without giving five years' advance written notice of such intention to such utility, except where such customer demonstrates to the Commission, after notice and opportunity for hearing, through clear and convincing evidence that its supplier has failed to perform, or has anticipatorily breached its duty to perform, or otherwise is about to fail to perform, through no fault of the customer, and that such customer is unable to obtain service at reasonable rates from an alternative supplier. If, as a result of such proceeding, the Commission finds it in the public interest to grant an exemption from the five-year notice requirement, such customer may thereafter purchase electric energy at the costs of such utility, as determined by the Commission pursuant to subdivision 3 d hereof, for the remainder of the five-year notice period, after which point the customer may purchase electric energy from the utility under rates, terms and conditions determined pursuant to § 56-585.1. However, such customer shall be allowed to individually purchase electric energy from the utility under rates, terms, and conditions determined pursuant to § 56-585.1 if, upon application by such customer, the Commission finds that neither such customer's incumbent electric utility nor retail customers of such utility that do not choose to obtain electric energy from alternate suppliers will be adversely affected in a manner contrary to the public interest by granting such petition. In making such determination, the Commission shall take into consideration, without limitation, the impact and effect of any and all other previously approved petitions of like type with respect to such incumbent electric utility. Any customer that returns to purchase electric energy from its incumbent electric utility, before or after expiration of the five-year notice period, shall be subject to minimum stay periods equal to those prescribed by the Commission pursuant to subdivision C 1.

d. The costs of serving a customer that has received an exemption from the five-year notice requirement under subdivision 3 c hereof shall be the market-based costs of the utility, including (i) the actual expenses of procuring such electric energy from the market, (ii) additional administrative and transaction costs associated with procuring such energy, including, but not limited to, costs of transmission, transmission line losses, and ancillary services, and (iii) a reasonable margin as determined pursuant to the provisions of subdivision A 2 of § 56-585.1. The methodology established by the Commission for determining such costs shall ensure that neither utilities nor other retail customers are adversely affected in a manner contrary to the public interest.

4. Two or more individual nonresidential retail customers of electric energy within the Commonwealth, whose individual demand during the most recent calendar year did not exceed five megawatts, may petition the Commission for permission to aggregate or combine their demands, for the purpose of meeting the demand limitations of subdivision 3, so as to become qualified to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth under the conditions specified in subdivision 3. The Commission may, after notice and opportunity for hearing, approve such petition if it finds that:

a. Neither such customers' incumbent electric utility nor retail customers of such utility that do not choose to obtain electric energy from alternate suppliers will be adversely affected in a manner contrary to the public interest by granting such petition. In making such determination, the Commission shall take into consideration, without limitation, the impact and effect of any and all other previously approved petitions of like type with respect to such incumbent electric utility; and

b. Approval of such petition is consistent with the public interest.

If such petition is approved, all customers whose load has been aggregated or combined shall thereafter be subject in all respects to the provisions of subdivision 3 and shall be treated as a single, individual customer for the purposes of said subdivision. In addition, the Commission shall impose reasonable periodic monitoring and reporting obligations on such customers to demonstrate that they continue, as a group, to meet the demand limitations of subdivision 3. If the Commission finds, after notice and opportunity for hearing, that such group of customers no longer meets the above demand limitations, the Commission may revoke its previous approval of the petition, or take such other actions as may be consistent with the public interest.

5. Individual retail customers of electric energy within the Commonwealth, regardless of customer class, shall be permitted:

a. To purchase electric energy provided 100 percent from renewable energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth, other than any incumbent electric utility that is not the incumbent electric utility serving the exclusive service territory in which such a customer is located, if the incumbent electric utility serving the exclusive service territory does not offer an approved tariff for electric energy provided 100 percent from renewable energy; and

b. To continue purchasing renewable energy pursuant to the terms of a power purchase agreement in effect on the date there is filed with the Commission a tariff for the incumbent electric utility that serves the exclusive service territory in which the customer is located to offer electric energy provided 100 percent from renewable energy, for the duration of such agreement.

6. To the extent that an incumbent electric utility has elected as of February 1, 2019, the Fixed Resource Requirement alternative as a Load Serving Entity in the PJM Region and continues to make such election and is therefore required to obtain capacity for all load and expected load growth in its service area, any customer of a utility subject to that requirement that purchases energy pursuant to subdivision 3 or 4 from a supplier licensed to sell retail electric energy within the Commonwealth shall continue to pay its incumbent electric utility for the non-fuel generation capacity and transmission related costs incurred by the incumbent electric utility in order to meet the customer's capacity obligations, pursuant to the incumbent electric utility's standard tariff that has been approved by and is

on file with the Commission. In the case of such customer, the advance written notice period established in subdivisions 3 c and d shall be three years. This subdivision shall not apply to the customers of licensed suppliers that (i) had an agreement with a licensed supplier entered into before February 1, 2019, or (ii) had aggregation petitions pending before the Commission prior to January 1, 2019, unless and until any customer referenced in clause (i) or (ii) has returned to purchase electric energy from its incumbent electric utility, pursuant to the provisions of subdivision 3 or 4, and is receiving electric energy from such incumbent electric utility.

7. A tariff for one or more classes of residential customers filed with the Commission for approval by a cooperative on or after July 1, 2010, shall be deemed to offer a tariff for electric energy provided 100 percent from renewable energy if it provides undifferentiated electric energy and the cooperative retires a quantity of renewable energy certificates equal to 100 percent of the electric energy provided pursuant to such tariff. A tariff for one or more classes of nonresidential customers filed with the Commission for approval by a cooperative on or after July 1, 2012, shall be deemed to offer a tariff for electric energy provided 100 percent from renewable energy if it provides undifferentiated electric energy and the cooperative retires a quantity of renewable energy certificates equal to 100 percent of the electric energy provided pursuant to such tariff. For purposes of this section, "renewable energy certificate" means, with respect to cooperatives, a tradable commodity or instrument issued by a regional transmission entity or affiliate or successor thereof in the United States that validates the generation of electricity from renewable energy sources or that is certified under a generally recognized renewable energy certificate standard. One renewable energy certificate equals 1,000 kWh or one MWh of electricity generated from renewable energy. A cooperative offering electric energy provided 100 percent from renewable energy pursuant to this subdivision that involves the retirement of renewable energy certificates shall disclose to its retail customers who express an interest in purchasing energy pursuant to such tariff (i) that the renewable energy is comprised of the retirement of renewable energy certificates, (ii) the identity of the entity providing the renewable energy certificates, and (iii) the sources of renewable energy being offered.

8. Retail competition for the purchase and sale of electric energy shall be subject to the following schedule:

a. As used in this subdivision 8:

"Renewable energy" has the meaning ascribed to it in § 56-576 except that it (i) does not include biomass, municipal solid waste, or electricity generated solely from pumped storage and (ii) does include run-of-river generation from a combined pumped storage and run-of-river facility.

"Renewable energy certificate" or "REC" means a certificate issued by an affiliate of the regional transmission entity of which the licensed supplier is a member, as it may change from time to time, or any successor to such affiliate, and held or acquired by such licensed supplier, that validates the generation of renewable energy by eligible sources in the interconnection region of the regional transmission entity.

b. The total electric energy sold to retail customers in Virginia by a supplier of electric energy licensed to sell retail electric energy within the Commonwealth shall be composed of the following amounts of electric energy from renewable energy sources, referred to herein as RPS Goals, in accordance with the schedule set out in the following table:

Year	*RPS Goal*
2021	*14%*
2022	*17%*
2023	*20%*
2024	*23%*
2025	*26%*
2026	*29%*
2027	*32%*
2028	*35%*
2029	*38%*
2030	*41%*
2031	*45%*
2032	*48%*
2033	*51%*
2034	*55%*
2035	*58%*
2036	*61%*
2037	*63%*
2038	*66%*
2039	*69%*
2040	*72%*
2041	*75%*

2042	*78%*
2043	*81%*
2044	*83%*
2045	*86%*
2046	*89%*
2047	*92%*
2048	*95%*
2049	*97%*
2050 and thereafter	*100%*

c. A licensed supplier may apply renewable energy sales achieved or renewable energy certificates acquired during the periods covered by any such goal that are in excess of the sales requirement for that goal to the sales requirements for any future goal in the five years after the renewable energy was generated or the renewable energy certificates were created.

d. Eligible renewable energy sources shall be categorized as follows:

(1) Tier 1 sources are renewable energy sources from offshore wind located off the coastline of, or interconnected in, the Commonwealth;

(2) Tier 2 sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have a capacity of three megawatts or less;

(3) Tier 2A sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity of 20 kilowatts or less. A minimum of 10 percent of all energy required from Tier 2A sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

(4) Tier 2B sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity that is between 20 kilowatts and 250 kilowatts. A minimum of 10 percent of all energy required from Tier 2B sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

(5) Tier 2C sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity between 250 kilowatts and 1,000 kilowatts. A minimum of 10 percent of all energy required from Tier 2C sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

(6) Tier 2D sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity between 1,000 kilowatts and 3,000 kilowatts. A minimum of 10 percent of all energy required from Tier 2D in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

(7) Tier 3 sources are renewable energy sources located in the Commonwealth or off the Commonwealth's coastline that produce electricity from sunlight, wind, wave motion, tides, geothermal power, or energy from waste or landfill gas;

(8) Tier 4 sources are renewable energy sources that are physically located in the PJM interconnection region or the interconnection region of the regional transmission entity of which the participating utility is a member, as it may change from time to time, that produce electricity from sunlight, wind, falling water, wave motion, tides, and geothermal power, subject to the constraint that an eligible renewable resource that produces electricity from falling water shall be limited to facilities with a generation capacity equal to or less than 65 megawatts and that began commercial operation after December 31, 1979; however, if a facility that produces electricity from falling water began incremental commercial operation after December 31, 1979, and such incremental energy generation is equal to or greater than 50 percent of the original nameplate rating, the facility shall qualify as a Tier 4 source regardless of the facility's output; and

(9) Tier 5 sources are renewable energy sources that are physically located in the PJM interconnection region or the interconnection region of the regional transmission entity of which the participating utility is a member, as it may change from time to time, that produce electricity from falling water and with which the utility has an existing contract on July 1, 2020.

e. Tiers 2A, 2B, 2C, and 2D sources shall be implemented in accordance with the following schedule:

Year	*Tier 2A*	*Tier 2B*	*Tier 2C*	*Tier 2D*
2021	*0.19%*	*0.13%*	*0.19%*	*0.13%*

2022	0.29%	0.19%	0.29%	0.19%
2023	0.38%	0.26%	0.38%	0.26%
2024	0.48%	0.32%	0.48&	0.32%
2025	0.57%	0.38%	0.57%	0.38%
2026	0.66%	0.44%	0.66%	0.44%
2027	0.75%	0.50%	0.75%	0.50%
2028	0.84%	0.56%	0.84%	0.56%
2029	0.92%	0.61%	0.92%	0.61%
2030	1.0%	0.66%	1.0%	0.66%
2031	1.03%	0.69%	1.03%	0.69%
2032	1.05%	0.70%	1.05%	0.70%
2033	1.08%	0.72%	1.08%	0.72%
2034	1.11%	0.74%	1.11%	0.74%
2035	1.15%	0.77%	1.15%	0.77%
2036	1.19%	0.80%	1.19%	0.80%
2037	1.24%	0.83%	1.24%	0.83%
2038	1.29%	0.86%	1.29%	0.86%
2039	1.34%	0.90%	1.34%	0.90%
2040	1.40%	0.93%	1.40%	0.93%
2041	1.46%	0.97%	1.46%	0.97%
2042	1.52%	1.01%	1.52%	1.01%
2043	1.58%	1.06%	1.58%	1.06%
2044	1.65%	1.10%	1.65%	1.10%
2045	1.72%	1.15%	1.72%	1.15%
2046	1.79%	1.20%	1.79%	1.20%
2047	1.87%	1.25%	1.87%	1.25%
2048	1.95%	1.30%	1.95%	1.30%
2049	2.03%	1.35%	2.03%	1.35%
2050 and thereafter	2.12%	1.41%	2.12%	1.41%

f. In:

(1) Any compliance year, no more than 878,500 RECs from facilities that produce electricity via energy from waste and no more than 654,000 RECs from facilities that produce electricity from landfill gas may be utilized to comply with the utility's RPS Goals. Only those facilities producing energy from waste and landfill gas in operation within the Commonwealth on July 1, 2020, are eligible to participate;

(2) Compliance years 2021 through 2035, no more than 2.5 million RECs from existing facilities as of December 31, 2020, that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4;

(3) Compliance years 2036 through 2042, no more than 3 million RECs from existing facilities as of December 31, 2020, that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4; and

(4) Compliance years 2043 and thereafter, no more than 3.5 million RECs from existing facilities as of December 31, 2020, that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4.

g. In each compliance year, a licensed supplier shall procure or produce a sufficient number of RECs from Tiers 1, 2, and 3 so as to meet the percentages set out in following table:

Date	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
2021	0%	3%	30%	38%	29%
2022	0%	5%	34%	45%	16%
2023	0%	6%	37%	51%	6%
2024	0%	7%	38%	49%	6%
2025	0%	7%	40%	48%	5%
2026	0%	8%	41%	47%	4%
2027	12%	8%	42%	34%	4%
2028	11%	9%	42%	35%	3%
2029	20%	9%	42%	26%	3%
2030	18%	9%	43%	27%	3%
2031	24%	9%	41%	23%	3%
2032	22%	8%	39%	28%	3%
2033	27%	8%	38%	25%	2%
2034	31%	8%	36%	23%	2%
2035	35%	8%	35%	20%	2%
2036	33%	8%	35%	22%	2%
2037	36%	8%	35%	20%	2%
2038	34%	7%	34%	23%	2%
2039	37%	7%	34%	20%	2%

2040	*35%*	*7%*	*33%*	*23%*	*2%*
2041	*38%*	*7%*	*33%*	*20%*	*2%*
2042	*36%*	*8%*	*33%*	*21%*	*2%*
2043	*39%*	*8%*	*33%*	*19%*	*1%*
2044	*37%*	*8%*	*34%*	*20%*	*1%*
2045	*39%*	*8%*	*34%*	*18%*	*1%*
2046	*38%*	*8%*	*34%*	*19%*	*1%*
2047	*40%*	*8%*	*34%*	*17%*	*1%*
2048	*39%*	*8%*	*34%*	*18%*	*1%*
2049	*40%*	*8%*	*35%*	*16%*	*1%*
2050 and thereafter	*39%*	*8%*	*35%*	*18%*	*0%*

RECs from Tiers 4 and 5 sources in excess of the percentages laid out in the table above may not be used by an electric utility to meet their annual RPS Goals.

h. A licensed supplier may apply renewable energy sales achieved or renewable energy certificates acquired in excess of the sales requirement for that RPS Goal to the sales requirements for any future RPS Goals in the five calendar years after the renewable energy was generated or the renewable energy certificates were created.

i. A specific deficiency payment shall apply to each tier identified in the table in subdivision g. If the licensed supplier is unable to meet the compliance obligation of any tier, or if the cost of a REC in that tier should exceed the per megawatt-hour cost of the deficiency payment, the supplier shall be obligated to make a deficiency payment equal to its megawatt-hour shortfall in the relevant tier for the year of noncompliance. If, in any year, a licensed supplier meets its compliance obligation for Tiers 1, 2, and 3, but does not meet their overall RPS Goal, it shall make a deficiency payment equal to the overall REC shortfall in that year multiplied by the Tier 3 deficiency payment in the same year. The deficiency payment for each tier will decline annually by 2.5 percent adjusted for inflation. The deficiency payments, on a per-megawatt basis, for each tier are as follows:

Tier 1: If compliance buyers are unable to meet their annual Tier 1 targets, they are obligated to procure two and one-half times RECs from Tier 3, 4, or 5 or pay two and one-half times the Tier 3 deficiency payment in that year.

Tier 2A: $115

Tier 2B: $100

Tier 2C: $80

Tier 2D: $70

Tier 3: $45

Tier 4: $0

Tier 5: $0

j. 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 shall distribute moneys in the account as following: (i) 50 percent of total revenue shall be directed to low-income, disability, veteran, and age-qualifying energy efficiency programs; (ii) 16 percent shall be directed to additional energy efficiency measures for public facilities; (iii) 30 percent shall be directed to low-income, disability, veteran, and age-qualifying renewable energy programs; and (iv) four percent shall be directed to administrative costs.

k. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subdivision 8, which rules and regulations shall include provisions specifying the commencement date of such minimum stay exemption program.

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

C. 1. By January 1, 2002, the Commission shall promulgate regulations establishing whether and, if so, for what minimum periods, customers who request service from an incumbent electric utility pursuant to subsection D of § 56-582 or a default service provider, after a period of receiving service from other suppliers of electric energy, shall be required to use such service from such incumbent electric utility or default service provider, as determined to be in the public interest by the Commission.

2. Subject to (i) the availability of capped rate service under § 56-582, and (ii) the transfer of the management and control of an incumbent electric utility's transmission assets to a regional transmission entity after approval of such transfer by the Commission under § 56-579, retail customers of such utility (a) purchasing such energy from licensed suppliers and (b) otherwise subject to minimum stay periods prescribed by the Commission pursuant to subdivision 1, shall nevertheless be exempt from any such minimum stay obligations by agreeing to purchase electric energy at the market-based costs of such utility or default providers after a period of obtaining electric energy from another supplier. Such costs shall include (i) the actual expenses of procuring such electric energy from the market, (ii) additional administrative and transaction costs associated with procuring such energy, including, but not limited to, costs of transmission, transmission line losses, and ancillary services, and (iii) a reasonable margin. The

methodology of ascertaining such costs shall be determined and approved by the Commission after notice and opportunity for hearing and after review of any plan filed by such utility to procure electric energy to serve such customers. The methodology established by the Commission for determining such costs shall be consistent with the goals of (a) promoting the development of effective competition and economic development within the Commonwealth as provided in subsection A of § 56-596, and (b) ensuring that neither incumbent utilities nor retail customers that do not choose to obtain electric energy from alternate suppliers are adversely affected.

3. Notwithstanding the provisions of subsection D of § 56-582 and subsection C of § 56-585, however, any such customers exempted from any applicable minimum stay periods as provided in subdivision 2 shall not be entitled to purchase retail electric energy thereafter from their incumbent electric utilities, or from any distributor required to provide default service under subsection B of § 56-585, at the capped rates established under § 56-582, unless such customers agree to satisfy any minimum stay period then applicable while obtaining retail electric energy at capped rates.

4. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subsection, which rules and regulations shall include provisions specifying the commencement date of such minimum stay exemption program.

§ 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. 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~~. 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 six 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;~~

If the Commission determines that the utility meets in any year the annual energy efficiency standards set forth in § 56-596.2, the Commission shall award a performance incentive, which shall be at least the additional recovery of a margin on efficiency program operating expenses in that year, to be recovered through a rate adjustment clause under this subdivision, 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. Such margin 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, to be included in the performance incentive, 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 incremental 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, with the exception of facilities declared in the public interest pursuant to Chapter 296 of the Acts of Assembly of 2018 and facilities utilizing energy derived from offshore wind, no utility may petition the Commission for construction of any new generating resources unless that utility has already met the energy savings goals identified in § 56-596.2 and the supply-side resources needs cannot be more affordably met with 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 and established an energy efficiency escrow account in which to deposit sums in lieu of payments for any rate adjustment clause approved by the Commission pursuant to this subdivision 5 c, for customer-directed investment in energy efficiency programs, in an amount at least as great as that customer's exempted payments for any rate adjustment clause approved by the Commission pursuant to this subdivision 5 c. 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; allow for year-to-year flexibility in customer use of energy efficiency escrow accounts; and require that each energy efficiency escrow account sunsets after five years, with any funds unused subject to forfeiture to the utility for use in support of utility energy efficiency programs. 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 a renewable energy portfolio standard program pursuant to § 56-585.2 that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs as are provided for in a program approved pursuant to § 56-585.2;

e. Projected and actual costs of projects that the Commission finds to be necessary 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.

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)~~, *other than those facilities declared in the public interest pursuant to Chapter 296 of the Acts of Assembly of 2018 and facilities utilizing energy derived from offshore wind*, 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. *Nothing in this subdivision shall be construed to prevent the utility from purchasing power on the open market for the health, well-being, or economic growth of the Commonwealth. In the case of a facility utilizing energy derived from offshore wind, regardless of cost recovery mechanisms, the utility shall identify options for utilizing local workers, consult with the Commonwealth's Chief Workforce Development Officer on opportunities to advance the Commonwealth's workforce goals, including furtherance of apprenticeship and other workforce training programs to develop the local workforce, and give priority to the hiring of local workers.* 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 cost adder. 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 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 50 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 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 50 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 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 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. As used in this section:

"BOEM" means the federal Bureau of Ocean Energy Management.

"Phase II Utility" means an investor-owned incumbent electric utility that was, as of July 1, 1999, bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002.

"Qualified developer" means a wind energy developer that a Phase II Utility determines to be capable of delivering the proposed project development services based on factors listed in subdivision C 9.

"Qualified offshore wind project" means an offshore wind generation facility that has a rated capacity of not less than 400 megawatts, with a primary point of interconnection within the Commonwealth or the Delmarva Peninsula, that has been selected by a Phase II Utility following a competitive solicitation conducted pursuant to subsection C, that has received approval by the Commission, and is located within either the Virginia WEA or another Eligible WEA.

"Virginia Wind Energy Area" means (i) the tract leased by a Phase II Utility from the BOEM

(Virginia WEA) or (ii) another eligible wind energy area for which the developer holds a lease from the BOEM (Eligible WEA).

B. Prior to January 1, 2034, and subject to the requirements of this section, a Phase II Utility shall construct, acquire, or purchase the energy and capacity from qualified offshore wind projects having an aggregate rated capacity of not less than 5,200 megawatts, subject to the requirements of this section. A Phase II Utility shall place 2,600 megawatts in service by 2030 and an additional 2,600 megawatts in service by 2034.

C. The Commission shall adopt regulations governing the competitive procurement and approval process for qualified offshore wind projects. The Commission's regulations shall incorporate the following requirements and standards:

1. On an annual basis, beginning no later than January 1, 2022, a Phase II Utility shall conduct a competitive solicitation to purchase from qualified developers the energy and renewable energy certificates associated with the development of a qualified offshore wind project within either the Virginia WEA or another Eligible WEA. In response to such solicitation, a qualified developer may offer to a Phase II Utility certain project development services from qualified developers, which may include development, engineering, procurement, and construction, including the interconnection, operation and maintenance, or decommissioning related to the development of a qualified offshore wind project within either the Virginia WEA or another Eligible WEA.

2. The regulations shall provide procedures for informing market participants regarding the terms and conditions of, and process for participating in, such competitive procurement activities.

3. Proposals shall be due within 180 days of the issuance of any solicitation.

4. In response to a solicitation for qualified offshore wind projects, a developer may submit one or more proposals of at least 400 megawatts that are located either (i) within an Eligible WEA that the developer has under lease or (ii) within the Virginia WEA.

5. For development activities within the Virginia WEA, a Phase II Utility shall ensure that the Virginia WEA includes qualified offshore wind projects developed and built by a minimum of two qualified developers. Prior to soliciting proposals, a Phase II Utility shall undertake and complete a study in consultation with experienced developers to determine the optimal way to apportion the Virginia WEA between two or more qualified developers.

6. Each solicitation shall request that developers specifically address the following factors for each proposed project:

a. Location of wind turbines within the Virginia WEA or another Eligible WEA, accounting for other projects contracted for or contemplated within the applicable WEA;

b. Point of interconnection and export cable routes, accounting for physical, environmental, and real estate constraints;

c. Expected annual energy production, substantiated by third-party validated reports;

d. Plans for securing all real estate, permits, and interconnection approvals and agreements, including an expected development budget;

e. Plans for executing the engineering, procurement, and construction of the project, including a budget for capital costs, substantiated by detailed budgets and third-party analysis or vendor commitments, where applicable;

f. Plans for executing the ongoing operations and maintenance of the project, including a budget for operating costs, substantiated by detailed budgets and third-party analysis or vendor commitments, where applicable;

g. Plans for executing the decommissioning of the project, including an expected budget;

h. Proposed commercial terms for executing the project development services, accounting for any rights and assets possessed by the developer;

i. Plans for realization of value associated with tax incentives, if applicable, or any other incentives; and

j. Analysis of the impact of the offshore wind project on energy costs and rates within the Commonwealth, accounting for impacts on wholesale energy prices and integrated resource planning.

7. Developers may propose their preferred form of consideration for the project development services as provided in subsection D.

8. A Phase II Utility shall determine whether a developer qualifies as a qualified developer after considering certain factors including the following:

a. The developer's experience in developing offshore wind projects;

b. The developer's experience in developing comparably sized projects in the United States; and

c. The developer's financial soundness.

9. In evaluating proposals received, a Phase II Utility shall take into consideration certain factors including the following:

a. Expected ratepayer impacts based on the expected development, capital, operating, and *decommissioning budgets provided by the developer and reviewed by an independent engineer retained by the Phase II Utility;*

b. Financial risk to be assumed by ratepayers under the commercial terms proposed by the developer;

c. Feasibility of the proposed development, construction, operations, and decommissioning plans proposed by the developer, as reviewed by an independent expert retained by the Phase II Utility;

d. Local economic benefits, investments, and job creation within the Commonwealth of Virginia; and

e. Other project feasibility considerations.

10. The Phase II Utility shall, within 90 days of receipt, select the proposal, or combination of proposals, that (i) presents the highest likelihood of enabling the utility to meet the schedule for offshore wind installations as required by this section and (ii) balances ratepayer impact and financial risk to the ratepayers, based on the commercial terms proposed by the developer.

11. The Phase II Utility shall, within 30 days of its selection, submit to the Commission a petition seeking approval of its selection and a positive prudency determination regarding the proposed transaction.

D. A Phase II Utility, or an affiliate thereof, shall have the option to own at least 50 percent of the equity of any qualified offshore wind project located within the Virginia WEA. A Phase II Utility may own up to 50 percent of the equity of any qualified offshore wind project located within any other Eligible WEA, subject to agreement between the Phase II Utility and the leaseholder for such non-Virginia Wind Energy Area, provided that a qualified developer shall be permitted to own the balance of the equity in a qualified offshore wind project, whether such project is located in the Virginia WEA or another Eligible WEA. Subject to the foregoing, allowable consideration for project development services may include the following:

1. A Phase II Utility may own 100 percent of the qualified offshore wind project, in which case the qualified developer receives either (i) recovery of all costs incurred plus a fee under a model to be proposed by the developer or (ii) recovery of a fixed budget, with a formula under which savings or overruns are shared, to be proposed by the developer;

2. A Phase II Utility and the qualified developer jointly own the qualified offshore wind project in a ratio proposed by the developer, with capital or services to be provided as proposed by the developer, provided that the qualified developer shall accept the same rate of return as that recovered by a Phase II Utility; or

3. A qualified developer and a Phase II Utility may enter into a power purchase agreement at a fixed price per megawatt-hour of energy delivered, under which a Phase II Utility or the qualified developer may own any fraction of the qualified offshore wind project.

E. A Phase II Utility shall be entitled to recover all prudently incurred costs associated with the equity percentage of a qualified offshore wind project owned by such utility from the utility's Virginia jurisdictional ratepayers through rates for generation and distribution services or through a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1. A Phase II Utility shall purchase the energy, capacity, and environmental attributes associated with the equity percentage of a qualified offshore wind project not owned by the utility, such costs being recoverable from the utility's Virginia jurisdictional ratepayers pursuant to § 56-249.6.

All costs associated with qualified offshore wind projects that are subject to competitive procurement pursuant to subsection C are deemed reasonably and prudently incurred, provided the Commission finds that the developer meets the requirements of a qualified developer; the project meets the requirements of a qualified offshore wind project; the Phase II Utility diligently considered the evaluation criteria and applied the selection criteria required by the Commission's regulations; and the project provides an equitable balance of risk and reward to each of the ratepayers, the utility, and the developers.

The Commission shall enter its final order with respect to any petition filed by the Phase II Utility for approval and a prudency determination within 60 days of the receipt of such petition.

F. Any contract awarded pursuant to this section shall stipulate that contractors or employees utilized for construction activities at the preassembly harbor shall be paid no less than the prevailing average wage as determined by the Virginia Employment Commission in the locality where the preassembly harbor is located.

G. It is in the public interest, and is the objective of the General Assembly, for a Phase II Utility to comply with the offshore wind procurement requirements of this section pursuant to the schedule described in subsection B.

§ 56-585.2. Sale of electricity from renewable sources through a renewable energy portfolio standard program.

A. As used in this section:

~~"Qualified investment" means an expense incurred in the Commonwealth by a participating utility in conducting, either by itself or in partnership with institutions of higher education in the Commonwealth or with industrial or commercial customers that have established renewable energy research and~~

~~development programs in the Commonwealth, research and development activities related to renewable or alternative energy sources, which expense (i) is designed to enhance the participating utility's understanding of emerging energy technologies and their potential impact on and value to the utility's system and customers within the Commonwealth; (ii) promotes economic development within the Commonwealth; (iii) supplements customer-driven alternative energy or energy efficiency initiatives; (iv) supplements alternative energy and energy efficiency initiatives at state or local governmental facilities in the Commonwealth; or (v) is designed to mitigate the environmental impacts of renewable energy projects.~~

"Accelerated renewable energy buyer" means a customer that is served within the commercial and industrial rate classes of a utility and that has indicated via a filing with the Commission that it intends to meet the compliance obligations laid out in subsections B and C via eligible contracts or commitments.

"Deployment" means the installation of energy storage systems through utility procurement, customer installation, or any other mechanism.

"Eligible contracts or commitments" to purchase renewable energy include power purchase agreements, contracts for differences or financial commitments resulting in the delivery of electric energy within the regional transmission entity of the customer's utility, and subscriptions to renewable energy tariffs offered by a utility.

"Energy storage system" means commercially available technology that is capable of absorbing energy and storing it for use at a later time. "Energy storage system" includes electrochemical, thermal, and electromechanical technologies. An energy storage system may have any of the following characteristics: (i) being either large scale or distributed or (ii) being either owned by a load-serving entity or local publicly owned electric utility, a customer of a load-serving entity or local publicly owned electric utility, or a third party, or is jointly owned by any number of such entities.

"Procure" means to acquire by ownership or by a contractual right to use services provided by an energy storage system.

"Renewable energy" ~~shall have~~ *has* the same meaning ascribed to it in § 56-576, *excluding any biomass and municipal solid waste other than energy from waste*, provided such renewable energy is (i) generated in the Commonwealth or in the interconnection region of the regional transmission entity of which the ~~participating~~ *electric* utility is a member, as it may change from time to time, and purchased by ~~a participating~~ *an electric* utility under a power purchase agreement~~;~~, provided, however, that if such agreement was executed on or after July 1, 2013, the agreement shall expressly transfer ownership of renewable attributes, in addition to ownership of the energy, to the ~~participating~~ *electric* utility; (ii) generated by a public utility providing electric service in the Commonwealth from a facility in which the public utility owns at least a 49 percent interest and that is located in the Commonwealth, in the interconnection region of the regional transmission entity of which the ~~participating~~ *electric* utility is a member, or in a control area adjacent to such interconnection region; or (iii) represented by renewable energy certificates. "Renewable energy" ~~shall~~ *does* not include electricity generated from pumped storage~~,~~ but ~~shall include~~ *includes* run-of-river generation from a combined pumped-storage and run-of-river facility.

"Renewable energy certificate" means ~~either (i)~~ a certificate issued by an affiliate of the regional transmission entity of which the ~~participating~~ *electric* utility is a member, as it may change from time to time, or any successor to such affiliate, and held or acquired by such *electric* utility, that validates the generation of renewable energy by eligible sources in the interconnection region of the regional transmission entity ~~or (ii) a certificate issued by the Commission pursuant to subsection J and held or acquired by a participating utility, that validates a qualified investment made by the participating utility~~.

"Total electric energy sold in the ~~base~~ *previous calendar* year" means total electric energy sold to Virginia jurisdictional retail customers by ~~a participating~~ *an electric* utility in *the previous* calendar year ~~2007~~, excluding an amount equivalent to ~~the average of~~ the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants ~~for the calendar years 2004 through 2006~~ *in the previous calendar year, provided such nuclear units were operating by July 1, 2020*.

B. ~~Any investor-owned incumbent~~ *Each* electric utility ~~may apply to the Commission for approval to~~ *shall* participate in a renewable energy portfolio standard program, as defined in this section. ~~The Commission shall approve such application if the applicant demonstrates that it has a reasonable expectation of achieving 12 percent of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15 percent of its base year electric energy sales from renewable energy sources during calendar year 2025, as provided in subsection D.~~

~~C. It is in the public interest for utilities that seek to have a renewable energy portfolio standard program to achieve the goals set forth in subsection D, such goals being referred to herein as "RPS Goals." A utility shall receive double credit toward meeting the renewable energy portfolio standard for energy derived from sunlight, from onshore wind, or from facilities in the Commonwealth fueled~~

~~primarily by animal waste, and triple credit toward meeting the renewable energy portfolio standard for energy derived from offshore wind.~~

~~D.~~ Regarding any renewable energy portfolio standard program, the total electric energy sold by ~~a~~ *an electric* utility to meet the RPS Goals shall be composed of the ~~following~~ amounts of electric energy or renewable thermal energy equivalent from renewable energy sources, as adjusted for any sales volumes lost through operation of the customer choice provisions of subdivision A 3 or ~~A~~ 4 of § 56-577~~:~~

~~RPS Goal I: In calendar year 2010, 4 percent of total electric energy sold in the base year.~~

~~RPS Goal II: For calendar years 2011 through 2015, inclusive, an average of 4 percent of total electric energy sold in the base year, and in calendar year 2016, 7 percent of total electric energy sold in the base year.~~

~~RPS Goal III: For calendar years 2017 through 2021, inclusive, an average of 7 percent of total electric energy sold in the base year, and in calendar year 2022, 12 percent of total electric energy sold in the base year.~~

~~RPS Goal IV: For calendar years 2023 and 2024, inclusive, an average of 12 percent of total electric energy sold in the base year, and in calendar year 2025, 15 percent of total electric energy sold in the base year.~~

~~A utility may not apply renewable energy certificates issued pursuant to subsection J to meet more than 20 percent of the sales requirement for the RPS Goal in any year.~~*, as set forth in the following table:*

Date	*RPS Goal*
2021	*14%*
2022	*17%*
2023	*20%*
2024	*23%*
2025	*26%*
2026	*29%*
2027	*32%*
2028	*35%*
2029	*38%*
2030	*41%*
2031	*45%*
2032	*48%*
2033	*51%*
2034	*55%*
2035	*58%*
2036	*61%*
2037	*63%*
2038	*66%*
2039	*69%*
2040	*72%*
2041	*75%*
2042	*78%*
2043	*81%*
2044	*83%*
2045	*86%*
2046	*89%*
2047	*92%*
2048	*95%*
2049	*97%*
2050 and thereafter	*100%*

A utility's RPS Goals shall be reduced in proportion to any sales volumes attributable to eligible contracts or commitments to purchase renewable energy of accelerated renewable energy buyers, as enumerated in subsection F. At least 35 percent of the renewable energy resources procured by a utility for purposes of complying with the RPS Goals shall be from the purchase of energy, capacity, or environmental attributes from facilities owned by persons other than a public utility.

C. Eligible renewable energy sources shall be categorized as follows:

1. Tier 1 sources are renewable energy sources from offshore wind located off the coastline of, or interconnected in, the Commonwealth;

2. Tier 2 sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have a capacity of three megawatts or less;

3. Tier 2A sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power *purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity of 20 kilowatts or less. A minimum of 10 percent of all energy required from Tier 2A sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;*

4. Tier 2B sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity that is between 20 kilowatts and 250 kilowatts. A minimum of 10 percent of all energy required from Tier 2B sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

5. Tier 2C sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity between 250 kilowatts and 1,000 kilowatts. A minimum of 10 percent of all energy required from Tier 2C sources in a given compliance year shall be sourced from low-to-moderate income (LMI) projects;

6. Tier 2D sources are renewable energy sources located in the Commonwealth that produce energy from sunlight, wind, or anaerobic digestion where the utility has not already entered into a power purchase agreement related to that facility pursuant to § 56-594, provided such facilities have an AC capacity between 1,000 kilowatts and 3,000 kilowatts. A minimum of 10 percent of all energy required from Tier 2D in a given compliance year shall be sourced from low-to-moderate income (LMI) projects.

7. Tier 3 sources are renewable energy sources located in the Commonwealth or off the Commonwealth's coastline that produce electricity from sunlight, wind, wave motion, tides, geothermal power, or energy from waste or landfill gas;

8. Tier 4 sources are renewable energy sources that are physically located in the PJM interconnection region or the interconnection region of the regional transmission entity of which the participating utility is a member, as it may change from time to time, that produce electricity from sunlight, wind, falling water, wave motion, tides, and geothermal power, subject to the constraint that an eligible renewable resource that produces electricity from falling water shall be limited to facilities with a generation capacity equal to or less than 65 megawatts and that began commercial operation after December 31, 1979; however, if a facility that produces electricity from falling water began incremental commercial operation after December 31, 1979, and such incremental energy generation is equal to or greater than 50 percent of the original nameplate rating, the facility shall qualify as a Tier 4 source regardless of the facility's output; and

9. Tier 5 sources are renewable energy sources that are physically located in the PJM interconnection region or the interconnection region of the regional transmission entity of which the participating utility is a member, as it may change from time to time, that produce electricity from falling water and with which the utility has an existing contract on July 1, 2020.

Tiers 2A, 2B, 2C, and 2D sources shall be implemented in accordance with the following schedule:

Year	*Tier 2A*	*Tier 2B*	*Tier 2C*	*Tier 2D*
2021	*0.19%*	*0.13%*	*0.19%*	*0.13%*
2022	*0.29%*	*0.19%*	*0.29%*	*0.19%*
2023	*0.38%*	*0.26%*	*0.38%*	*0.26%*
2024	*0.48%*	*0.32%*	*0.48&*	*0.32%*
2025	*0.57%*	*0.38%*	*0.57%*	*0.38%*
2026	*0.66%*	*0.44%*	*0.66%*	*0.44%*
2027	*0.75%*	*0.50%*	*0.75%*	*0.50%*
2028	*0.84%*	*0.56%*	*0.84%*	*0.56%*
2029	*0.92%*	*0.61%*	*0.92%*	*0.61%*
2030	*1.0%*	*0.66%*	*1.0%*	*0.66%*
2031	*1.03%*	*0.69%*	*1.03%*	*0.69%*
2032	*1.05%*	*0.70%*	*1.05%*	*0.70%*
2033	*1.08%*	*0.72%*	*1.08%*	*0.72%*
2034	*1.11%*	*0.74%*	*1.11%*	*0.74%*
2035	*1.15%*	*0.77%*	*1.15%*	*0.77%*
2036	*1.19%*	*0.80%*	*1.19%*	*0.80%*
2037	*1.24%*	*0.83%*	*1.24%*	*0.83%*
2038	*1.29%*	*0.86%*	*1.29%*	*0.86%*
2039	*1.34%*	*0.90%*	*1.34%*	*0.90%*
2040	*1.40%*	*0.93%*	*1.40%*	*0.93%*
2041	*1.46%*	*0.97%*	*1.46%*	*0.97%*
2042	*1.52%*	*1.01%*	*1.52%*	*1.01%*
2043	*1.58%*	*1.06%*	*1.58%*	*1.06%*
2044	*1.65%*	*1.10%*	*1.65%*	*1.10%*
2045	*1.72%*	*1.15%*	*1.72%*	*1.15%*

2046	*1.79%*	*1.20%*	*1.79%*	*1.20%*
2047	*1.87%*	*1.25%*	*1.87%*	*1.25%*
2048	*1.95%*	*1.30%*	*1.95%*	*1.30%*
2049	*2.03%*	*1.35%*	*2.03%*	*1.35%*
2050 and thereafter	*2.12%*	*1.41%*	*2.12%*	*1.41%*

D. In:

1. Any compliance year, no more than 878,500 RECs from facilities that produce electricity via energy from waste and no more than 654,000 RECs from facilities that produce electricity from landfill gas may be utilized to comply with the utility's RPS Goals. Only those facilities producing energy from waste and landfill gas in operation within the Commonwealth on July 1, 2020, are eligible to participate;

2. Compliance years 2021 through 2035, no more than 2.5 million RECs from existing facilities as of December 31, 2020, that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4.;

3. Compliance years 2036 through 2042, no more than 3.0 million RECs from existing facilities as of December 31, 2020 that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4; and

4. Compliance years 2043 and thereafter, no more than 3.5 million RECs from existing facilities as of December 31, 2020 that produce electricity from falling water may be used to meet the utility's compliance obligation under Tier 4.

In any compliance year, each electric utility shall procure or produce a sufficient number of RECs from Tiers 1, 2, and 3 so as to meet the percentages set out in the following table:

Date	*Tier 1*	*Tier 2*	*Tier 3*	*Tier 4*	*Tier 5*
2021	*0%*	*3%*	*30%*	*38%*	*29%*
2022	*0%*	*5%*	*34%*	*45%*	*16%*
2023	*0%*	*6%*	*37%*	*51%*	*6%*
2024	*0%*	*7%*	*38%*	*49%*	*6%*
2025	*0%*	*7%*	*40%*	*48%*	*5%*
2026	*0%*	*8%*	*41%*	*47%*	*4%*
2027	*12%*	*8%*	*42%*	*34%*	*4%*
2028	*11%*	*9%*	*42%*	*35%*	*3%*
2029	*20%*	*9%*	*42%*	*26%*	*3%*
2030	*18%*	*9%*	*43%*	*27%*	*3%*
2031	*24%*	*9%*	*41%*	*23%*	*3%*
2032	*22%*	*8%*	*39%*	*28%*	*3%*
2033	*27%*	*8%*	*38%*	*25%*	*2%*
2034	*31%*	*8%*	*36%*	*23%*	*2%*
2035	*35%*	*8%*	*35%*	*20%*	*2%*
2036	*33%*	*8%*	*35%*	*22%*	*2%*
2037	*36%*	*8%*	*35%*	*20%*	*2%*
2038	*34%*	*7%*	*34%*	*23%*	*2%*
2039	*37%*	*7%*	*34%*	*20%*	*2%*
2040	*35%*	*7%*	*33%*	*23%*	*2%*
2041	*38%*	*7%*	*33%*	*20%*	*2%*
2042	*36%*	*8%*	*33%*	*21%*	*2%*
2043	*39%*	*8%*	*33%*	*19%*	*1%*
2044	*37%*	*8%*	*34%*	*20%*	*1%*
2045	*39%*	*8%*	*34%*	*18%*	*1%*
2046	*38%*	*8%*	*34%*	*19%*	*1%*
2047	*40%*	*8%*	*34%*	*17%*	*1%*
2048	*39%*	*8%*	*34%*	*18%*	*1%*
2049	*40%*	*8%*	*35%*	*16%*	*1%*
2050 and thereafter	*39%*	*8%*	*35%*	*18%*	*0%*

RECs from Tiers 4 and 5 sources in excess of the percentages laid out in the table above may not be used by an electric utility to meet its annual RPS Goals. All of the renewable energy resources used by a utility for compliance with the RPS Goals, including new construction, and energy, capacity, and renewable energy certificate purchases, shall be subject to competitive procurement.

~~A~~ *An electric* utility may apply renewable energy sales achieved or renewable energy certificates acquired ~~during the periods covered by any such RPS Goal that are~~ in excess of the sales requirement for that RPS Goal to the sales requirements for ~~any~~ future RPS Goals in the five calendar years after the renewable energy was generated or the renewable energy certificates were created~~, except that a utility shall be able to apply renewable energy certificates acquired by the utility prior to January 1, 2014~~.

E. A specific deficiency payment shall apply to each tier identified in the table in subsection D. If the electric utility is unable to meet the compliance obligation of any tier, or if the cost of a REC in that tier should exceed the per megawatt-hour cost of the deficiency payment, the electric utility shall be *obligated to make a deficiency payment equal to its megawatt-hour shortfall in the relevant tier for the year of noncompliance. If, in any year, an electric utility meets its compliance obligation for Tiers 1, 2, and 3, but does not meet its overall RPS Goal, it shall make a deficiency payment equal to the overall REC shortfall in that year multiplied by the Tier 3 deficiency payment in the same year. The deficiency payment for each tier will decline annually by 2.5 percent adjusted for inflation. The deficiency payments, on a per megawatt-hour basis, for each tier are as follows:*

Tier 1: If compliance buyers are unable to meet their annual Tier 1 targets, they are obligated to procure two and one-half times RECs from Tier 3, 4, or 5 or pay two and one-half times the Tier 3 deficiency payment in that year.

Tier 2A: $115

Tier 2B: $100

Tier 2C: $80

Tier 2D: $70

Tier 3: $45

Tier 4: $0

Tier 5: $0

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 shall manage the account as following: (i) 50 percent of total revenue shall be directed to low-income, disability, veteran, and age-qualifying energy efficiency programs; (ii) 16 percent shall be directed to additional energy efficiency measures for public facilities; (iii) 30 percent shall be directed to low-income, disability, veteran, and age-qualifying renewable energy programs; and (iv) four percent shall be directed to administrative costs.

~~E.~~ ~~A~~ *F. An electric* utility ~~participating in such program~~ shall have the right to recover all *reasonable and prudent* incremental costs incurred for the purpose of ~~such participation in~~ *complying with the requirements of* such program, as accrued against income, through rate adjustment clauses as provided in subdivisions A 5 and ~~A~~ 6 of § 56-585.1, including, but not limited to, administrative costs, ancillary costs, capacity costs, costs of energy represented by certificates described in subsection A, and, in the case of construction of renewable energy generation facilities, allowance for funds used during construction until such time as an enhanced rate of return, as determined pursuant to subdivision A 6 of § 56-585.1, on construction work in progress is included in rates, projected construction work in progress, planning, development and construction costs, life-cycle costs, and costs of infrastructure associated therewith, plus an enhanced rate of return, as determined pursuant to subdivision A 6 of § 56-585.1*, except that a utility shall not recover any costs associated with the construction of renewable energy generation facilities unless such facilities are developed through transparent and competitive solicitation processes as detailed in subsection G and the Commission finds such costs to be reasonable and prudent*. ~~This subsection shall not apply to qualified investments as provided in subsection K.~~ All incremental costs of the RPS program shall be allocated to and recovered from the utility's customer classes based on the demand created by the class and within the class based on energy used by the individual customer in the class, except that the incremental costs of the RPS program shall not be allocated to or recovered from customers that ~~are served within the large industrial rate classes of the participating utilities and that are served at primary or transmission voltage~~ *the Commission certifies as an accelerated renewable energy buyer. The Commission shall certify an applicant as an accelerated renewable energy buyer if, on an annual basis, the applicant demonstrates that it has met the obligations enumerated in subsections B and C via the retirement of renewable energy credits from eligible resources or met the deficiency payment obligations stipulated in subsection D. All renewable energy certificates retired via this process shall not be credited toward a utility's RPS Goals. The Commission may establish any standards or application procedures it deems necessary to implement the requirements of this subsection.*

~~F.~~ ~~A~~ *G. For the purposes of obtaining resources to meet any Tier III compliance obligation, a utility shall at least once per year conduct a request for proposals for renewable energy pursuant to this subsection. Such requests for proposals for Tier III resources 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. 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) explicit 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. For the purposes of obtaining resources to meet any Tier 2 compliance obligation, a utility shall conduct, and evaluate the results of, requests for proposals pursuant to the terms of this subsection, except that such utility shall give preference to renewable energy certificates generated at facilities located in the Commonwealth and owned by third parties. Notwithstanding the foregoing, if a utility is not able to procure eligible resources at reasonable cost from facilities owned by third parties, a utility may comply with its Tier 2 compliance obligation by utilizing energy generated at utility-owned facilities. The staff of the Commission shall oversee and review the results of any request for proposals for Tier 2 resources conducted pursuant to this subsection. The staff of the Commission, during any proceeding in which a utility seeks to recover from ratepayers any costs associated with the procurement of Tier 2 resources, shall provide its opinion as to whether the utility has complied with the terms of this subsection. A Phase II Utility shall comply with the requirements of this subsection and the competitive procurement requirements described in § 56-585.1:11 prior to using offshore wind resources to comply with any RPS Goal.*

H. An electric utility ~~participating in such program~~ shall apply ~~towards~~ *toward* meeting its RPS Goals any renewable energy from existing renewable energy sources owned by the ~~participating~~ *electric* utility or purchased as allowed by contract at no additional cost to customers to the extent feasible. A utility participating in such program shall not apply ~~towards~~ *toward* meeting its RPS Goals renewable energy certificates attributable to any renewable energy generated at a renewable energy generation source in operation as of July 1, 2007, that is operated by a person that is served within a utility's large industrial rate class and that is served at primary or transmission voltage, except for those persons providing renewable thermal energy equivalents to the utility. A participating utility shall be required to fulfill any remaining deficit needed to fulfill its RPS Goals from new renewable energy supplies at reasonable cost and in a prudent manner to be determined by the Commission at the time of approval of any application made pursuant to subsection B. ~~A participating utility may sell renewable energy certificates produced at its own generation facilities located in the Commonwealth or, if located outside the Commonwealth, owned by such utility and in operation as of January 1, 2010, or renewable energy certificates acquired as part of a purchase power agreement, to another entity and purchase lower cost renewable energy certificates and the net difference in price between the renewable energy certificates shall be credited to customers. Utilities participating in such program shall collectively, either through the installation of new generating facilities, through retrofit of existing facilities or through purchases of electricity from new facilities located in Virginia, use or cause to be used no more than a total of 1.5 million tons per year of green wood chips, bark, sawdust, a tree or any portion of a tree which is used or can be used for lumber and pulp manufacturing by facilities located in Virginia, towards meeting RPS goals, excluding such fuel used at electric generating facilities using wood as fuel prior to January 1, 2007. A utility with an approved application shall be allocated a portion of the 1.5 million tons per year in proportion to its share of the total electric energy sold in the base year, as defined in subsection A, for all utilities participating in the RPS program. A utility may use in meeting RPS goals, without limitation, the following sustainable biomass and biomass based waste to energy resources: mill residue, except wood chips, sawdust and bark; pre-commercial soft wood thinning; slash; logging and construction debris; brush; yard waste; shipping crates; dunnage; non-merchantable waste paper; landscape or right-of-way tree trimmings; agricultural and vineyard materials; grain; legumes; sugar; and gas produced from the anaerobic decomposition of animal waste.~~

~~G.~~ *I.* The Commission shall ~~promulgate~~ *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 ~~goals~~ *Goals* are met in accordance with this section.

~~H.~~ *J. The Commission shall open up a proceeding to identify and develop appropriate mechanisms and programs to achieve a 2,400 megawatt energy storage deployment target for the Commonwealth. No later than January 1, 2021, the Commission shall adopt regulations for the implementation of the energy storage deployment target. The regulations shall outline a deployment target of 2,400 megawatts by 2035. The regulations shall set forth the following interim targets: 100 megawatts by December 31, 2021; 300 megawatts by December 31, 2023; 600 megawatts by December 31, 2025; 900 megawatts by December 31, 2027; 1,200 megawatts by December 31, 2029; 1,600 megawatts by December 31, 2031; 2,000 megawatts by December 31, 2033, and 2,400 megawatts by December 31, 2035. Interim energy storage targets are cumulative and include Commission-approved energy storage system resources procured by a utility required to file a joint triennial integrated resource plan so long as the*

Commission approval date is after July 1, 2010. The deployment target shall be met through eligible energy storage systems. A single energy storage system shall not be used to meet more than 25 percent of the deployment target in any year. The programs and mechanisms explored in this proceeding shall include competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs. In developing these programs, the Commission shall engage stakeholders with opportunities for written comment and workshops to solicit input on the development of the programs. The Commission shall update existing utility planning and procurement regulations of electric utilities to incorporate requirements to procure energy storage resources. In adopting regulations to realize the energy storage deployment targets, the Commission shall incorporate the following elements:

1. Require that at least 10 percent of the interim storage targets be realized through distribution-connected systems, inclusive of customer-sited locations;

2. Include provisions and programs that ensure competitive deployment of energy storage services from third parties; and

3. Require the inclusion of an energy storage plan in the electric utility's integrated resource plan containing a description of the electric utility's progress toward meeting the energy storage deployment target and a demonstration of how the electric utility plans to meet or exceed the energy storage deployment target.

K. Each ~~investor-owned~~ ~~incumbent~~ electric utility shall report to the Commission annually by November 1 identifying:

1. The utility's efforts~~, if~~ ~~any,~~ to meet the RPS Goals, specifically identifying:

a. A list of all states where the purchased or owned renewable energy was generated, specifying the number of megawatt hours or renewable energy certificates originating from each state;

b. A list of the decades in which the purchased or owned renewable energy generating units were placed in service, specifying the number of megawatt hours or renewable energy certificates originating from those units; and

c. A list of fuel types used to generate the purchased or owned renewable energy, specifying the number of megawatt hours or renewable energy certificates originating from each fuel type;

2. The utility's overall generation of renewable energy; ~~and~~

3. Advances in renewable generation technology that affect activities described in subdivisions 1 and 2*; and*

4. The electric utility's efforts to meet the energy storage target, specifically identifying:

a. The utility's proposal to meet or exceed the interim and 2030 energy storage target that fall within the action plan period;

b. A summary of all energy storage system projects for which a utility seeks approval in the action plan or the distributed resource plan;

c. A description of how energy storage system resources are being modeled and considered in the existing planning process;

d. An evaluation of the cost and benefits for the deployment of energy storage, including a description of the electric utility's cost-benefit analysis framework; and

e. A description of how energy storage resources are being modeled and considered in the existing planning process, including whether the modeling tools were instructed to select energy storage technologies as part of the modeling exercise and what the energy storage cost assumptions were and the source and date of those cost assumptions.

~~I.~~ *L.* The Commission shall post on its website the reports submitted by each investor-owned incumbent electric utility pursuant to subsection ~~H~~ *J.*

~~J. The Commission shall issue to a participating utility a number of renewable energy certificates for qualified investments, upon request by a participating utility, if it finds that an expense satisfies the conditions set forth in this section for a qualified investment, as follows:~~

~~1. By March 31 of each year, the participating utility shall provide an analysis, as reasonably determined by a qualified independent broker, of the average for the preceding year of the publicly available prices for Tier 1 renewable energy certificates and Tier 2 renewable energy certificates, validating the generation of renewable energy by eligible sources, that were issued in the interconnection region of the regional transmission entity of which the participating utility is a member;~~

~~2. In the same annual analysis provided to the Commission, the participating utility shall divide the amount of the participating utility's qualified investments in the applicable period by the average price determined pursuant to subdivision 1;~~

~~3. The number of renewable energy certificates to be issued to the participating utility shall equal the product obtained pursuant to subdivision 2; and~~

~~4. The Commission shall review and validate the analysis provided by the participating utility within 90 days of submittal of its analysis to the Commission. If no corrections are made by the Commission, then the analysis shall be deemed correct and the renewable energy certificates shall be deemed issued~~

~~to the participating utility.~~

~~Each renewable energy certificate issued to a participating utility pursuant to this subsection shall represent the equivalent of one megawatt hour of renewable energy sales achieved when applied to an RPS Goal.~~

~~K. Qualified investments shall constitute reasonable and prudent operating expenses of a participating utility. Notwithstanding subsection E, a participating utility shall not be authorized to recover the costs associated with qualified investments through rate adjustment clauses as provided in subdivisions A 5 and A 6 of § 56-585.1. In any proceeding conducted pursuant to § 56-585.1 or other provision of this title in which a participating utility seeks recovery of its qualified investments as an operating expense, the participating utility shall not be authorized to earn a return on its qualified investments.~~

~~L. A participating utility shall not be eligible for a research and development tax credit pursuant to § 58.1-439.12:08 or 58.1-439.12:11 with regard to any expense incurred or investment made by the participating utility that constitutes a qualified investment pursuant to this section.~~

§ 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:

"Applicable bill credit rate" means the dollar-per-kilowatt hour rate used to calculate the subscriber's bill credit. The applicable bill credit rate shall be such that the shared solar program results in the robust project deployment and shared solar program access for all customer classes.

"Bill credit" means the monetary value of the electricity, in kilowatt-hours, generated by the shared solar facility allocated to a subscriber to offset that subscriber's electricity bill.

"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~~ *three* megawatt 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 *150 percent* 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 an individual or household with an income of not more than 80 percent of the area median income based on U.S. Department of Housing and Urban Development guidelines.

"Low-income service organization" means a non-residential customer of the investor-owned utilities whose primary purpose is to serve low-income individuals and households.

"Low-income shared solar facility" means a shared solar facility where at least 50 percent of the capacity of the facility is subscribed by low-income customers or low-income service organizations.

"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.

"Shared solar facility" means a facility that:

1. Generates electricity by means of a solar photovoltaic device with a nameplate capacity rating that does not exceed 3,000 kilowatts of alternating current;

2. Is operated pursuant to a program whereby at least three subscribers receive a bill credit for the electricity generated from the facility in proportion to the size of their subscription;

3. Is connected to the electric distribution grid serving the Commonwealth;

4. Has at least three subscribers;

5. Has at least 40 percent of its capacity subscribed by customers with subscriptions of 25 kilowatts or less; and

6. Is located on a single parcel of land.

"Shared solar program" or "program" means the program created through the adoption of rules to allow for the development of shared solar facilities described in subsection H.

"Subscriber" means a retail customer of a utility that (i) owns one or more subscriptions of a shared solar facility that is interconnected with the utility and (ii) receives service in the service territory of the same utility in whose service territory the shared solar facility is located.

"Subscriber organization" means any for-profit or nonprofit entity that owns or operates one or more shared solar facilities. A subscriber organization shall not be considered a utility solely as a result of its ownership or operation of a shared solar facility

"Subscription" means a contract or other agreement between a subscriber and the owner of a shared solar facility. A subscription shall be sized such that the estimated bill credits do not exceed the subscriber's average annual bill for the customer account to which the subscription is attributed.

"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~~ *10* percent 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.

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 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.

G. For purposes of this section, the Commission shall liberally construe eligible customer-generators' *rights to contract with other persons to own or operate, or both, an electrical generating facility, and such rights include the right to finance electrical generating facilities via leases and power purchase agreements. Nothing in this section shall be construed as (i) rendering any person who contracts with such eligible customer-generator pursuant to this section to be a public utility or a competitive service provider; (ii) imposing a requirement that such a person meet 100 percent of the load requirements for each customer account it serves; or (iii) affecting leases, power purchase agreements, or other third-party financing arrangements in effect prior to July 1, 2020.*

H. An investor owned utility shall provide a bill credit to a subscriber's subsequent monthly electric bill for the proportional output of a shared solar facility attributable to that subscriber. The shared solar program shall be administered as follows:

1. The value of the bill credit for the subscriber shall be calculated by multiplying the subscriber's portion of the kilowatt-hour electricity production from the shared solar facility by the applicable bill credit rate for the subscriber. Any amount of the bill credit that exceeds the subscriber's monthly bill shall be carried over and applied to the next month's bill in perpetuity;

2. The utility shall provide bill credits to a shared solar facility's subscribers for not less than 25 years from the date the shared solar facility becomes commercially operational;

3. The subscriber organization shall, on a monthly basis and in a standardized electronic format, provide to the investor-owned utility a subscriber list indicating the kilowatt-hours of generation attributable to each of the retail customers participating in a shared solar facility in accordance with the subscriber's portion of the output of the shared solar facility;

4. Subscriber lists may be updated monthly to reflect canceling subscribers and to add new subscribers. The investor owned utility shall apply bill credits to subscriber bills within one billing cycle following the cycle during which the energy was generated by the shared solar facility;

5. The investor owned utility shall, on a monthly basis and in a standardized electronic format, provide to the subscriber organization a report indicating the total value of bill credits generated by the shared solar facility in the prior month, as well as the amount of the bill credit applied to each subscriber;

6. A subscriber organization may accumulate bill credits in the event that all of the electricity generated by a shared solar facility is not allocated to subscribers in a given month. On an annual basis, the subscriber organization shall furnish to the utility allocation instructions for distributing excess bill credits to subscribers; and

7. All environmental attributes associated with a shared solar facility, including renewable energy certificates, shall be considered property of the subscriber organization. At the subscriber organization's discretion, distributed to the subscribers, sold to load-serving entities with compliance obligations, as laid out in §§ 56-577 and 56-582.2, or other buyers, banked for up to five years, or retired.

I. Each subscriber shall receive an applicable bill credit based on the subscriber's customer class. Each class applicable credit rate shall be calculated by the Commission annually by dividing revenues to the class by sales, measured in kilowatt-hours, to that class to yield a bill credit rate for the class ($/kWh). Annual sales and revenue should be data as reported to the Energy Information Agency via EIA form 861 or comparable data.

J. The Commission shall establish by regulation a shared solar program that complies with the provisions of subsections H and I by January 1, 2021, and shall require each investor-owned utility to file any tariffs, agreements, or forms necessary for implementation of the program. Any rule or utility implementation filings approved by the Commission shall:

1. Reasonably allow for the creation and financing of shared solar facilities;

2. Allow all customer classes to participate in the program and ensure participation opportunities for all customer classes;

3. Shall not remove a customer from its otherwise applicable customer class in order to participate in a shared solar facility;

4. Reasonably allow for the transferability and portability of subscriptions, including allowing a subscriber to retain a subscription to a shared solar facility if the subscriber moves within the same utility territory;

5. Establish uniform standards, fees, and processes for the interconnection of shared solar facilities that allow the utility to recover reasonable interconnection costs for each shared solar facility;

6. Adopt standardized consumer disclosure forms;

7. Allow the investor owned utilities to recover reasonable costs of administering the program;

8. Ensure non-discriminatory and efficient requirements and utility procedures for interconnecting projects;

9. Address the colocation of two or more shared solar facilities on a single parcel of land, and provide guidelines for determining when two or more facilities are co-located; and

10. Include a program implementation schedule.

Within 180 days of finalization of the Commission's adoption of regulations for the shared solar program, utilities shall begin crediting subscriber accounts of each shared solar facility interconnected in its service territory.

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

§ 56-596.2. Energy efficiency programs.

A. Each Phase I Utility and Phase II Utility, as such terms are defined in subdivision A 1 of § 56-585.1, 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 *approved costs of* energy efficiency programs shall *be allocated to programs designed to* benefit low-income, elderly, ~~and~~ *or* disabled individuals *or veterans*.

B. Notwithstanding any other provision of law, each investor-owned incumbent electric utility shall achieve the following incremental annual energy efficiency savings, as measured by the total combined kilowatt-hour savings achieved by deployed efficiency measures in their first year, provided that excess first-year savings in one year may be carried forward to the following compliance year:

1. In calendar year 2021, at least 0.35 percent of the average annual energy retail sales by that utility in the three preceding calendar years;

2. In calendar year 2022, at least 0.70 percent of the average annual energy retail sales by that utility in the three preceding calendar years;

3. In calendar year 2023, at least 1.0 percent of the average annual energy retail sales by that utility in the three preceding calendar years;

4. In calendar year 2024, at least 1.25 percent of the average annual energy retail sales by that utility in the three preceding calendar years;

5. In calendar year 2025, at least 1.50 percent of the average annual energy retail sales by that utility in the three preceding calendar years;

6. In calendar year 2026, at least 1.75 percent of the average annual energy retail sales by that utility in the three preceding calendar years; and

7. In calendar year 2027 and each calendar year thereafter, at least 2.0 percent of the average annual energy retail sales by that utility in the three preceding calendar years.

C. Excess first-year measure savings in any one year may be carried forward to the following compliance year, provided that (i) the amount of any savings carried forward shall not exceed 33 percent of the next year's required savings and (ii) any such savings carried forward shall not be used toward claiming any performance incentive set forth in subdivision A 5 c of § 56-585.1.

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 incremental 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 incremental annual energy efficiency savings set forth in subsection B. Utilities shall utilize the services of a third party to perform evaluation, measurement, and verification services to determine a utility's incremental net 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.

2. That Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, are repealed.

3. That the eleventh enactment of Chapter 296 of the Acts of Assembly of 2018 is repealed.

4. That the repeal of Chapters 358 and 382 of the Acts of Assembly of 2013, as amended by Chapter 803 of the Acts of Assembly of 2017, shall not affect third-party power purchase agreements authorized thereby that are in effect on July 1, 2020.

5. That the Department of Mines, Minerals and Energy shall prepare a report to the House and Senate Committees 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.

6. That in promulgating its regulation to reduce carbon dioxide emissions from covered units described in § 10.1-1308 of the Code of Virginia, as amended by this act, the State Air Pollution Control Board shall consult with the Department of Mines, Minerals and Energy, the State Corporation Commission, the Office of the Attorney General, and appropriate stakeholders and report to the General Assembly by January 1, 2021, 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.