

20109763D

HOUSE BILL NO. 1526

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the Joint Conference Committee on March 5, 2020)

(Patron Prior to Substitute—Delegate Sullivan)

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

Be it enacted by the General Assembly of Virginia:

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

§ 10.1-1308. Regulations.

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

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

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

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

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

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

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

HOUSE SUBSTITUTE

HB1526H2

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

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

65 **§ 56-576. Definitions.**

66 As used in this chapter:

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

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

81 (Expires December 31, 2023) "Business park" means a land development containing a minimum of
82 100 contiguous acres classified as a Tier 4 site under the Virginia Economic Development Partnership's
83 Business Ready Sites Program that is developed and constructed by an industrial development authority,
84 or a similar political subdivision of the Commonwealth created pursuant to § 15.2-4903 or other act of
85 the General Assembly, in order to promote business development and that is located in an area of the
86 Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury via his
87 delegation of authority to the Internal Revenue Service.

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

90 "Commission" means the State Corporation Commission.

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

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

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

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

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

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

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

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

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

112 "Electric distribution grid transformation project" means a project associated with electric distribution
113 infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate
114 the integration of utility-owned or customer-owned renewable electric generation resources with the
115 utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric
116 distribution grid security, customer service, or energy efficiency and conservation, including advanced
117 metering infrastructure; intelligent grid devices for real time system and asset information; automated
118 control systems for electric distribution circuits and substations; communications networks for service
119 meters; intelligent grid devices and other distribution equipment; distribution system hardening projects
120 for circuits, other than the conversion of overhead tap lines to underground service, and substations
121 designed to reduce service outages or service restoration times; physical security measures at key

122 distribution substations; cyber security measures; energy storage systems and microgrids that support
 123 circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy
 124 supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED
 125 street light conversions; and new customer information platforms designed to provide improved customer
 126 access, greater service options, and expanded access to energy usage information.

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

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

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

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

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

153 "Incumbent electric utility" means each electric utility in the Commonwealth that, prior to July 1,
 154 1999, supplied electric energy to retail customers located in an exclusive service territory established by
 155 the Commission.

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

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

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

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

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

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

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

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

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

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

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

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

221 *"Renewable thermal energy" means the thermal energy output from (i) a renewable-fueled combined*
222 *heat and power generation facility that is (a) constructed, or renovated and improved, after January 1,*
223 *2012, (b) located in the Commonwealth, and (c) utilized in industrial processes other than the combined*
224 *heat and power generation facility or (ii) a solar energy system, certified to the OG-100 standard of the*
225 *Solar Ratings and Certification Corporation or an equivalent certification body, that (a) is constructed, or*
226 *renovated and improved, after January 1, 2013, (b) is located in the Commonwealth, and (c) heats water*
227 *or air for residential, commercial, institutional, or industrial purposes.*

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

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

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

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

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

244 *"Rooftop solar installation" means a distributed electric generation facility, storage facility, or*

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

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

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

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

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

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

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

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

272 **§ 56-585.1. Generation, distribution, and transmission rates after capped rates terminate or**
 273 **expire.**

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

306 base rates. Commencing in 2011, the Commission, after notice and opportunity for hearing, shall
307 conduct reviews of the rates, terms and conditions for the provision of generation, distribution and
308 transmission services by each investor-owned incumbent electric utility, subject to the following
309 provisions:

310 1. Rates, terms and conditions for each service shall be reviewed separately on an unbundled basis,
311 and such reviews shall be conducted in a single, combined proceeding. Pursuant to subsection A of
312 § 56-585.1:1, the Commission shall conduct a review for a Phase I Utility in 2020, utilizing the three
313 successive 12-month test periods beginning January 1, 2017, and ending December 31, 2019. Thereafter,
314 reviews for a Phase I Utility will be on a triennial basis with subsequent proceedings utilizing the three
315 successive 12-month test periods ending December 31 immediately preceding the year in which such
316 review proceeding is conducted. Pursuant to subsection A of § 56-585.1:1, the Commission shall conduct
317 a review for a Phase II Utility in 2021, utilizing the four successive 12-month test periods beginning
318 January 1, 2017, and ending December 31, 2020, with subsequent reviews on a triennial basis utilizing
319 the three successive 12-month test periods ending December 31 immediately preceding the year in which
320 such review proceeding is conducted. All such reviews occurring after December 31, 2017, shall be
321 referred to as triennial reviews. For purposes of this section, a Phase I Utility is an investor-owned
322 incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by
323 the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an
324 investor-owned incumbent electric utility that was bound by such a settlement.

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

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

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

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

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

368 then the lower limit imposed by subdivision 2 a on the return to be determined by the Commission for
 369 such utility shall be calculated, for that Current Proceeding only, by increasing the Initial Return by a
 370 percentage at least equal to the increase, expressed as a percentage, in the United States Average
 371 Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor
 372 Statistics of the United States Department of Labor, since the date on which the Commission determined
 373 the Initial Return. For purposes of this subdivision:

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

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

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

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

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

389 g. If the combined rate of return on common equity earned by the generation and distribution
 390 services is no more than 50 basis points above or below the return as so determined or, for any test
 391 period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a
 392 Phase I Utility, such return is no more than 70 basis points above or below the return as so determined,
 393 such combined return shall not be considered either excessive or insufficient, respectively. However, for
 394 any test period commencing after December 31, 2012, for a Phase II Utility, and after December 31,
 395 2013, for a Phase I Utility, if the utility has, during the test period or periods under review, earned
 396 below the return as so determined, whether or not such combined return is within 70 basis points of the
 397 return as so determined, the utility may petition the Commission for approval of an increase in rates in
 398 accordance with the provisions of subdivision 8 a as if it had earned more than 70 basis points below a
 399 fair combined rate of return, and such proceeding shall otherwise be conducted in accordance with the
 400 provisions of this section. The provisions of this subdivision are subject to the provisions of subdivision
 401 8.

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

405 3. Each such utility shall make a triennial filing by March 31 of every third year, with such filings
 406 commencing for a Phase I Utility in 2020, and such filings commencing for a Phase II Utility in 2021,
 407 consisting of the schedules contained in the Commission's rules governing utility rate increase
 408 applications. Such filing shall encompass the three successive 12-month test periods ending December
 409 31 immediately preceding the year in which such proceeding is conducted, except that the filing for a
 410 Phase II Utility in 2021 shall encompass the four successive 12-month test periods ending December 31,
 411 2020, and in every such case the filing for each year shall be identified separately and shall be
 412 segregated from any other year encompassed by the filing. If the Commission determines that rates
 413 should be revised or credits be applied to customers' bills pursuant to subdivision 8 or 9, any rate
 414 adjustment clauses previously implemented related to facilities utilizing simple-cycle combustion turbines
 415 described in subdivision 6, shall be combined with the utility's costs, revenues and investments until the
 416 amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall
 417 combine such clauses with the utility's costs, revenues and investments only after it makes its initial
 418 determination with regard to necessary rate revisions or credits to customers' bills, and the amounts
 419 thereof, but after such clauses are combined as herein specified, they shall thereafter be considered part
 420 of the utility's costs, revenues, and investments for the purposes of future triennial review proceedings.
 421 In a triennial filing under this subdivision that does not result in an overall rate change a utility may
 422 propose an adjustment to one or more tariffs that are revenue neutral to the utility.

423 4. (Expires December 31, 2023) The following costs incurred by the utility shall be deemed
 424 reasonable and prudent: (i) costs for transmission services provided to the utility by the regional
 425 transmission entity of which the utility is a member, as determined under applicable rates, terms and
 426 conditions approved by the Federal Energy Regulatory Commission; (ii) costs charged to the utility that
 427 are associated with demand response programs approved by the Federal Energy Regulatory Commission
 428 and administered by the regional transmission entity of which the utility is a member; and (iii) costs

429 incurred by the utility to construct, operate, and maintain transmission lines and substations installed in
 430 order to provide service to a business park. Upon petition of a utility at any time after the expiration or
 431 termination of capped rates, but not more than once in any 12-month period, the Commission shall
 432 approve a rate adjustment clause under which such costs, including, without limitation, costs for
 433 transmission service; charges for new and existing transmission facilities, including costs incurred by the
 434 utility to construct, operate, and maintain transmission lines and substations installed in order to provide
 435 service to a business park; administrative charges; and ancillary service charges designed to recover
 436 transmission costs, shall be recovered on a timely and current basis from customers. Retail rates to
 437 recover these costs shall be designed using the appropriate billing determinants in the retail rate
 438 schedules.

439 4. (Effective January 1, 2024) The following costs incurred by the utility shall be deemed reasonable
 440 and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity
 441 of which the utility is a member, as determined under applicable rates, terms and conditions approved
 442 by the Federal Energy Regulatory Commission, and (ii) costs charged to the utility that are associated
 443 with demand response programs approved by the Federal Energy Regulatory Commission and
 444 administered by the regional transmission entity of which the utility is a member. Upon petition of a
 445 utility at any time after the expiration or termination of capped rates, but not more than once in any
 446 12-month period, the Commission shall approve a rate adjustment clause under which such costs,
 447 including, without limitation, costs for transmission service, charges for new and existing transmission
 448 facilities, administrative charges, and ancillary service charges designed to recover transmission costs,
 449 shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall
 450 be designed using the appropriate billing determinants in the retail rate schedules.

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

454 a. Incremental costs described in clause (vi) of subsection B of § 56-582 incurred between July 1,
 455 2004, and the expiration or termination of capped rates, if such utility is, as of July 1, 2007, deferring
 456 such costs consistent with an order of the Commission entered under clause (vi) of subsection B of
 457 § 56-582. The Commission shall approve such a petition allowing the recovery of such costs that
 458 comply with the requirements of clause (vi) of subsection B of § 56-582;

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

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

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

482 *Prior to January 1, 2022, the Commission shall award a margin for recovery on operating expenses*
 483 *for energy efficiency programs and pilot programs, which margin shall be equal to the general rate of*
 484 *return on common equity determined as described in subdivision 2. Beginning January 1, 2022, and*
 485 *thereafter, if the Commission determines that the utility meets in any year the annual energy efficiency*
 486 *standards set forth in § 56-596.2, in the following year, the Commission shall award a margin on*
 487 *energy efficiency program operating expenses in that year, to be recovered through a rate adjustment*
 488 *clause, which margin shall be equal to the general rate of return on common equity determined as*
 489 *described in subdivision 2. If the Commission does not approve energy efficiency programs that, in the*
 490 *aggregate, can achieve the annual energy efficiency standards, the Commission shall award a margin on*

491 energy efficiency operating expenses in that year for any programs the Commission has approved, to be
 492 recovered through a rate adjustment clause under this subdivision, which margin shall equal the general
 493 rate of return on common equity determined as described in subdivision 2. Any margin awarded
 494 pursuant to this subdivision shall be applied as part of the utility's next rate adjustment clause true-up
 495 proceeding. The Commission shall also award an additional 20 basis points for each additional
 496 incremental 0.1 percent in annual savings in any year achieved by the utility's energy efficiency
 497 programs approved by the Commission pursuant to this subdivision, beyond the annual requirements set
 498 forth in § 56-596.2, provided that the total performance incentive awarded in any year shall not exceed
 499 10 percent of that utility's total energy efficiency program spending in that same year.

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

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

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

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

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

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

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

549 e. Projected and actual costs of projects that the Commission finds to be necessary to mitigate
 550 impacts to marine life caused by construction of offshore wind generating facilities, as described in
 551 § 56-585.1:11, or to comply with state or federal environmental laws or regulations applicable to

552 generation facilities used to serve the utility's native load obligations, *including the costs of allowances*
553 *purchased through a market-based trading program for carbon dioxide emissions.* The Commission shall
554 approve such a petition if it finds that such costs are necessary to comply with such environmental laws
555 or regulations; and

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

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

566 6. To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the
567 utility's projected native load obligations and to promote economic development, a utility may at any
568 time, after the expiration or termination of capped rates, petition the Commission for approval of a rate
569 adjustment clause for recovery on a timely and current basis from customers of the costs of (i) a
570 coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the
571 Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or
572 without the utility's service territory, (ii) one or more other generation facilities, (iii) one or more major
573 unit modifications of generation facilities, including the costs of any system or equipment upgrade,
574 system or equipment replacement, or other cost reasonably appropriate to extend the combined operating
575 license for or the operating life of one or more generation facilities utilizing nuclear power, (iv) one or
576 more new underground facilities to replace one or more existing overhead distribution facilities of 69
577 kilovolts or less located within the Commonwealth, (v) one or more pumped hydroelectricity generation
578 and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their
579 power source and such facilities and associated resources are located in the coalfield region of the
580 Commonwealth as described in § 15.2-6002, regardless of whether such facility is located within or
581 without the utility's service territory, or (vi) one or more electric distribution grid transformation
582 projects; however, subject to the provisions of the following sentence, the utility shall not file a petition
583 under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental
584 increase in the level of investments associated with such a petition that exceeds five percent of such
585 utility's distribution rate base, as such rate base was determined for the most recently ended 12-month
586 test period in the utility's latest review proceeding conducted pursuant to subdivision 3 and concluded by
587 final order of the Commission prior to the date of filing of such petition under clause (iv). In all
588 proceedings regarding petitions filed under clause (iv) or (vi), the level of investments approved for
589 recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously
590 approved for recovery in prior proceedings under clause (iv) or (vi), as applicable. As of December 1,
591 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs
592 associated with conversions of overhead distribution facilities to underground facilities that have been
593 previously approved or are pending approval by the Commission through a petition by the utility under
594 this subdivision. Such a petition concerning facilities described in clause (ii) that utilize nuclear power,
595 facilities described in clause (ii) that are coal-fueled and will be built by a Phase I Utility, or facilities
596 described in clause (i) may also be filed before the expiration or termination of capped rates. A utility
597 that constructs or makes modifications to any such facility, or purchases any facility consisting of at
598 least one megawatt of generating capacity using energy derived from sunlight and located in the
599 Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more
600 Virginia businesses, shall have the right to recover the costs of the facility, as accrued against income,
601 through its rates, including projected construction work in progress, and any associated allowance for
602 funds used during construction, planning, development and construction or acquisition costs, life-cycle
603 costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs
604 of infrastructure associated therewith, plus, as an incentive to undertake such projects, an enhanced rate
605 of return on common equity calculated as specified below; however, in determining the amounts
606 recoverable under a rate adjustment clause for new underground facilities, the Commission shall not
607 consider, or increase or reduce such amounts recoverable because of (a) the operation and maintenance
608 costs attributable to either the overhead distribution facilities being replaced or the new underground
609 facilities or (b) any other costs attributable to the overhead distribution facilities being replaced.
610 Notwithstanding the preceding sentence, the costs described in clauses (a) and (b) thereof shall remain
611 eligible for recovery from customers through the utility's base rates for distribution service. A utility
612 filing a petition for approval to construct or purchase a facility consisting of at least one megawatt of
613 generating capacity using energy derived from sunlight and located in the Commonwealth and that

614 utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses may
615 propose a rate adjustment clause based on a market index in lieu of a cost of service model for such
616 facility. A utility seeking approval to construct or purchase a generating facility described in clause (i)
617 or (ii) that emits carbon dioxide shall demonstrate that it has already met the energy savings goals
618 identified in § 56-596.2 and that the identified need cannot be met more affordably through the
619 deployment or utilization of demand-side resources or energy storage resources and that it has
620 considered and weighed alternative options, including third-party market alternatives, in its selection
621 process.

622 The costs of the facility, other than return on projected construction work in progress and allowance
623 for funds used during construction, shall not be recovered prior to the date a facility constructed by the
624 utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility
625 becomes the owner of a purchased generation facility consisting of at least one megawatt of generating
626 capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or
627 services sourced, in whole or in part, from one or more Virginia businesses, or the date new
628 underground facilities are classified by the utility as plant in service. *In any application to construct a
629 new generating facility, the utility shall include, and the Commission shall consider, the social cost of
630 carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The
631 Commission shall ensure that the development of new, or expansion of existing, energy resources or
632 facilities does not have a disproportionate adverse impact on historically economically disadvantaged
633 communities. The Commission may adopt any rules it deems necessary to determine the social cost of
634 carbon and shall use the best available science and technology, including the Technical Support
635 Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under
636 Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse
637 Gases from the United States Government in August 2016, as guidance. The Commission shall include a
638 system to adjust the costs established in this section with inflation.*

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

675 period with new underground facilities in order to improve electric service reliability is in the public
 676 interest. In determining whether to approve petitions for rate adjustment clauses for such new
 677 underground facilities that meet this criteria, and in determining the level of costs to be recovered
 678 thereunder, the Commission shall liberally construe the provisions of this title.

679 The conversion of any such facilities on or after September 1, 2016, is deemed to provide local and
 680 system-wide benefits and to be cost beneficial, and the costs associated with such new underground
 681 facilities are deemed to be reasonably and prudently incurred and, notwithstanding the provisions of
 682 subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision,
 683 provided that the total costs associated with the replacement of any subset of existing overhead
 684 distribution tap lines proposed by the utility with new underground facilities, exclusive of financing
 685 costs, shall not exceed an average cost per customer of \$20,000, with such customers, including those
 686 served directly by or downline of the tap lines proposed for conversion, and, further, such total costs
 687 shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of
 688 \$750,000. A utility shall, without regard for whether it has petitioned for any rate adjustment clause
 689 pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for
 690 electric distribution grid transformation projects. Any plan for electric distribution grid transformation
 691 projects shall include both measures to facilitate integration of distributed energy resources and measures
 692 to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the
 693 Commission shall consider whether the utility's plan for such projects, and the projected costs associated
 694 therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without
 695 regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the
 696 costs associated with such projects will be recovered through a rate adjustment clause under this
 697 subdivision or through the utility's rates for generation and distribution services; and without regard to
 698 whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision
 699 8 d. The Commission's final order regarding any such petition for approval of an electric distribution
 700 grid transformation plan shall be entered by the Commission not more than six months after the date of
 701 filing such petition. The Commission shall likewise enter its final order with respect to any petition by a
 702 utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived
 703 from sunlight, pursuant to subsection D of § 56-580, within six months after the date of filing such
 704 petition. The basis points to be added to the utility's general rate of return to calculate the enhanced rate
 705 of return on common equity, and the first portion of that facility's service life to which such enhanced
 706 rate of return shall be applied, shall vary by type of facility, as specified in the following table:

707 Type of Generation Facility	Basis Points	First Portion of Service Life
708 Nuclear-powered	200	Between 12 and 25 years
709 Carbon capture compatible, clean-coal 710 powered	200	Between 10 and 20 years
711 Renewable powered, other than landfill 712 gas powered	200	Between 5 and 15 years
713 Coalbed methane gas powered	150	Between 5 and 15 years
714 Landfill gas powered	200	Between 5 and 15 years
715 Conventional coal or combined-cycle 716 combustion turbine	100	Between 10 and 20 years

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

724 For generating facilities within the Commonwealth utilizing nuclear power or those utilizing energy
 725 derived from offshore wind projects located in waters off the Commonwealth's Atlantic shoreline, such
 726 facilities shall continue to be eligible for an enhanced rate of return on common equity during the
 727 construction phase of the facility and the approved first portion of its service life of between 12 and 25
 728 years in the case of a facility utilizing nuclear power and for a service life of between 5 and 15 years in
 729 the case of a facility utilizing energy derived from offshore wind, provided, however, that, as of July 1,
 730 2013, the enhanced return for such facilities constructed pursuant to clause (ii) shall be 100 basis points,
 731 which shall be added to the utility's general rate of return as determined under subdivision 2. Thirty
 732 percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1,
 733 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred
 734 by the utility and recovered through a rate adjustment clause under this subdivision at such time as the
 735 Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of
 736 all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall
 737 not be deferred for recovery through a rate adjustment clause under this subdivision; however, such

738 remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by
 739 the Commission in the test periods under review in the utility's next review filed after July 1, 2014.
 740 Thirty percent of all costs of such a facility utilizing energy derived from offshore wind that the utility
 741 incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December
 742 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this
 743 subdivision at such time as the Commission provides in an order approving such a rate adjustment
 744 clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1,
 745 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under
 746 this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through
 747 existing base rates as determined by the Commission in the test periods under review in the utility's next
 748 review filed after July 1, 2014.

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

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

756 ~~Construction~~ Notwithstanding any provision of Chapter 296 of the Acts of Assembly of 2018,
 757 construction, purchasing, or leasing activities for a new utility-owned and utility-operated generating
 758 facility or facilities utilizing energy derived from sunlight or from onshore wind with an aggregate
 759 capacity of 5,000 16,100 megawatts, including rooftop solar installations with a capacity of not less than
 760 50 kilowatts, and with an aggregate capacity of 50 100 megawatts, together with a new test or
 761 demonstration project for a utility-owned and utility-operated generating facility or facilities utilizing
 762 energy derived from offshore wind with an aggregate capacity of not more than 16 3,000 megawatts, are
 763 in the public interest. To the extent that a utility elects to recover the costs of any such new generation
 764 facility or facilities through its rates for generation and distribution services and does not petition and
 765 receive approval from the Commission for recovery of such costs through a rate adjustment clause
 766 described in clause (ii), the Commission shall, upon the request of the utility in a triennial review
 767 proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d
 768 with respect to all costs deemed reasonable and prudent by the Commission in a proceeding pursuant to
 769 subsection D of § 56-580 or in a triennial review proceeding.

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

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

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

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

797 Notwithstanding any other provision of this subdivision, if the Commission finds during the triennial
 798 review conducted for a Phase II Utility in 2021 that such utility has not filed applications for all

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

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

822 7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a
823 stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any
824 costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the
825 Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or
826 that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to
827 new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and
828 records of the utility until the Commission's final order in the matter, or until the implementation of any
829 applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in
830 subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of
831 such petition, or during the consideration thereof by the Commission, that are proposed for recovery in
832 such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of
833 subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of
834 subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the
835 books and records of the utility until the Commission's final order in the matter, or until the
836 implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs
837 prudently incurred after the expiration or termination of capped rates related to other matters described
838 in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped
839 rates, provided, however, that no provision of this act shall affect the rights of any parties with respect
840 to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia
841 Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset
842 for regulatory accounting and ratemaking purposes under which it shall defer its operation and
843 maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant
844 and (ii) other work at such plant normally performed during a refueling outage. The utility shall
845 amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning
846 with the month in which such plant resumes operation after such refueling. The refueling cycle shall be
847 the applicable period of time between planned refueling outages for such plant. As of January 1, 2014,
848 such amortized costs are a component of base rates, recoverable in base rates only ratably over the
849 refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable
850 in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage
851 commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs
852 of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with
853 respect to triennial filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to
854 § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection
855 B. This provision shall not be deemed to change or reset base rates.

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

861 8. In any triennial review proceeding, for the purposes of reviewing earnings on the utility's rates for
862 generation and distribution services, the following utility generation and distribution costs not proposed
863 for recovery under any other subdivision of this subsection, as recorded per books by the utility for
864 financial reporting purposes and accrued against income, shall be attributed to the test periods under
865 review and deemed fully recovered in the period recorded: costs associated with asset impairments
866 related to early retirement determinations made by the utility for utility generation facilities fueled by
867 coal, natural gas, or oil or for automated meter reading electric distribution service meters; costs
868 associated with projects necessary to comply with state or federal environmental laws, regulations, or
869 judicial or administrative orders relating to coal combustion by-product management that the utility does
870 not petition to recover through a rate adjustment clause pursuant to subdivision 5 e; costs associated
871 with severe weather events; and costs associated with natural disasters. Such costs shall be deemed to
872 have been recovered from customers through rates for generation and distribution services in effect
873 during the test periods under review unless such costs, individually or in the aggregate, together with the
874 utility's other costs, revenues, and investments to be recovered through rates for generation and
875 distribution services, result in the utility's earned return on its generation and distribution services for the
876 combined test periods under review to fall more than 50 basis points below the fair combined rate of
877 return authorized under subdivision 2 for such periods or, for any test period commencing after
878 December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to fall
879 more than 70 basis points below the fair combined rate of return authorized under subdivision 2 for
880 such periods. In such cases, the Commission shall, in such triennial review proceeding, authorize
881 deferred recovery of such costs and allow the utility to amortize and recover such deferred costs over
882 future periods as determined by the Commission. The aggregate amount of such deferred costs shall not
883 exceed an amount that would, together with the utility's other costs, revenues, and investments to be
884 recovered through rates for generation and distribution services, cause the utility's earned return on its
885 generation and distribution services to exceed the fair rate of return authorized under subdivision 2, less
886 50 basis points, for the combined test periods under review or, for any test period commencing after
887 December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to exceed
888 the fair rate of return authorized under subdivision 2 less 70 basis points. Nothing in this section shall
889 limit the Commission's authority, pursuant to the provisions of Chapter 10 (§ 56-232 et seq.), including
890 specifically § 56-235.2, following the review of combined test period earnings of the utility in a triennial
891 review, for normalization of nonrecurring test period costs and annualized adjustments for future costs,
892 in determining any appropriate increase or decrease in the utility's rates for generation and distribution
893 services pursuant to subdivision 8 a or 8 c.

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

895 a. ~~The Revenue reductions related to energy efficiency measures or programs approved and deployed~~
896 ~~since the utility's previous triennial review have caused the utility, as verified by the Commission, during~~
897 ~~the test period or periods under review, considered as a whole, to earn more than 50 basis points below~~
898 ~~a fair combined rate of return on its generation and distribution services or, for any test period~~
899 ~~commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase~~
900 ~~I Utility, more than 70 basis points below a fair combined rate of return on its generation and~~
901 ~~distribution services, as determined in subdivision 2, without regard to any return on common equity or~~
902 ~~other matters determined with respect to facilities described in subdivision 6, the Commission shall~~
903 ~~order increases to the utility's rates for generation and distribution services necessary to recover such~~
904 ~~revenue reductions. If the Commission finds, for reasons other than revenue reductions related to energy~~
905 ~~efficiency measures, that the utility has, during the test period or periods under review, considered as a~~
906 ~~whole, earned more than 50 basis points below a fair combined rate of return on its generation and~~
907 ~~distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility~~
908 ~~and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined~~
909 ~~rate of return on its generation and distribution services, as determined in subdivision 2, without regard~~
910 ~~to any return on common equity or other matters determined with respect to facilities described in~~
911 ~~subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the~~
912 ~~opportunity to fully recover the costs of providing the utility's services and to earn not less than such~~
913 ~~fair combined rate of return, using the most recently ended 12-month test period as the basis for~~
914 ~~determining the amount of the rate increase necessary. However, in the first triennial review proceeding~~
915 ~~conducted after January 1, 2021, for a Phase II Utility, the Commission may not order a rate increase,~~
916 ~~and in all triennial reviews of a Phase I or Phase II utility, the Commission may not order such rate~~
917 ~~increase unless it finds that the resulting rates are necessary to provide the utility with the opportunity to~~
918 ~~fully recover its costs of providing its services and to earn not less than a fair combined rate of return~~
919 ~~on both its generation and distribution services, as determined in subdivision 2, without regard to any~~
920 ~~return on common equity or other matters determined with respect to facilities described in subdivision~~
921 ~~6, using the most recently ended 12-month test period as the basis for determining the permissibility of~~

922 any rate increase under the standards of this sentence, and the amount thereof; and provided that, solely
923 in connection with making its determination concerning the necessity for such a rate increase or the
924 amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1,
925 2028, exclude from this most recently ended 12-month test period any remaining investment levels
926 associated with a prior customer credit reinvestment offset pursuant to subdivision d.

927 b. The utility has, during the test period or test periods under review, considered as a whole, earned
928 more than 50 basis points above a fair combined rate of return on its generation and distribution
929 services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after
930 December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of
931 return on its generation and distribution services, as determined in subdivision 2, without regard to any
932 return on common equity or other matters determined with respect to facilities described in subdivision
933 6, the Commission shall, subject to the provisions of subdivisions 8 d and 9, direct that 60 percent of
934 the amount of such earnings that were more than 50 basis points, or, for any test period commencing
935 after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, that
936 70 percent of the amount of such earnings that were more than 70 basis points, above such fair
937 combined rate of return for the test period or periods under review, considered as a whole, shall be
938 credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as
939 determined at the discretion of the Commission, following the effective date of the Commission's order,
940 and shall be allocated among customer classes such that the relationship between the specific customer
941 class rates of return to the overall target rate of return will have the same relationship as the last
942 approved allocation of revenues used to design base rates; or

943 c. In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after
944 January 1, 2021, for a Phase II Utility in which the utility has, during the test period or test periods
945 under review, considered as a whole, earned more than 50 basis points above a fair combined rate of
946 return on its generation and distribution services or, for any test period commencing after December 31,
947 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis
948 points above a fair combined rate of return on its generation and distribution services, as determined in
949 subdivision 2, without regard to any return on common equity or other matter determined with respect
950 to facilities described in subdivision 6, and the combined aggregate level of capital investment that the
951 Commission has approved other than those capital investments that the Commission has approved for
952 recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the
953 test periods under review in that triennial review proceeding in new utility-owned generation facilities
954 utilizing energy derived from sunlight, or from wind, and in electric distribution grid transformation
955 projects, as determined pursuant to subdivision 8 d, does not equal or exceed 100 percent of the
956 earnings that are more than 70 basis points above the utility's fair combined rate of return on its
957 generation and distribution services for the combined test periods under review in that triennial review
958 proceeding, the Commission shall, subject to the provisions of subdivision 9 and in addition to the
959 actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate.
960 However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility,
961 any reduction to the utility's rates ordered by the Commission pursuant to this subdivision shall not
962 exceed \$50 million in annual revenues, with any reduction allocated to the utility's rates for generation
963 services, and in each triennial review of a Phase I or Phase II Utility, the Commission may not order
964 such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to
965 fully recover its costs of providing its services and to earn not less than a fair combined rate of return
966 on its generation and distribution services, as determined in subdivision 2, without regard to any return
967 on common equity or other matters determined with respect to facilities described in subdivision 6,
968 using the most recently ended 12-month test period as the basis for determining the permissibility of any
969 rate reduction under the standards of this sentence, and the amount thereof; and

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

984 capital under clauses (i) and (ii) is referred to in this subdivision as the customer credit reinvestment
 985 offset, which offsets the customer bill credit amount that the utility has invested or will invest in new
 986 solar or wind generation facilities or electric distribution grid transformation projects for the benefit of
 987 customers, in amounts up to 100 percent of earnings that are more than 70 basis points above the
 988 utility's fair rate of return on its generation and distribution services, and thereby reduce or eliminate
 989 otherwise incremental rate adjustment clause charges and increases to customer bills, which is deemed to
 990 be in the public interest. If 100 percent of the amount of earnings that are more than 70 basis points
 991 above the utility's fair combined rate of return on its generation and distribution services, as determined
 992 in subdivision 2, exceeds the aggregate level of invested capital in new utility-owned generation
 993 facilities utilizing energy derived from sunlight, or from wind, and electric distribution grid
 994 transformation projects, as provided in clauses (i) and (ii), during the test period or periods under
 995 review, then 70 percent of the amount of such excess shall be credited to customer bills as provided in
 996 subdivision 8 b in connection with the triennial review proceeding. The portion of any costs associated
 997 with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or
 998 electric distribution grid transformation projects that is the subject of any customer credit reinvestment
 999 offset pursuant to this subdivision shall not thereafter be recovered through the utility's rates for
 1000 generation and distribution services over the service life of such facilities and shall not thereafter be
 1001 included in the utility's costs, revenues, and investments in future triennial review proceedings conducted
 1002 pursuant to subdivision 2 and shall not be the subject of a rate adjustment clause petition pursuant to
 1003 subdivision 6. The portion of any costs associated with new utility-owned generation facilities utilizing
 1004 energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is
 1005 not the subject of any customer credit reinvestment offset pursuant to this subdivision may be recovered
 1006 through the utility's rates for generation and distribution services over the service life of such facilities
 1007 and shall be included in the utility's costs, revenues, and investments in future triennial review
 1008 proceedings conducted pursuant to subdivision 2 until such costs are fully recovered, and if such costs
 1009 are recovered through the utility's rates for generation and distribution services, they shall not be the
 1010 subject of a rate adjustment clause petition pursuant to subdivision 6. Only the portion of such costs of
 1011 new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric
 1012 distribution grid transformation projects that has not been included in any customer credit reinvestment
 1013 offset pursuant to this subdivision, and not otherwise recovered through the utility's rates for generation
 1014 and distribution services, may be the subject of a rate adjustment clause petition by the utility pursuant
 1015 to subdivision 6.

1016 The Commission's final order regarding such triennial review shall be entered not more than eight
 1017 months after the date of filing, and any revisions in rates or credits so ordered shall take effect not more
 1018 than 60 days after the date of the order. The fair combined rate of return on common equity determined
 1019 pursuant to subdivision 2 in such triennial review shall apply, for purposes of reviewing the utility's
 1020 earnings on its rates for generation and distribution services, to the entire three successive 12-month test
 1021 periods ending December 31 immediately preceding the year of the utility's subsequent triennial review
 1022 filing under subdivision 3 and shall apply to applicable rate adjustment clauses under subdivisions 5 and
 1023 6 prospectively from the date the Commission's final order in the triennial review proceeding, utilizing
 1024 rate adjustment clause true-up protocols as the Commission in its discretion may determine.

1025 9. If, as a result of a triennial review required under this subsection and conducted with respect to
 1026 any test period or periods under review ending later than December 31, 2010 (or, if the Commission has
 1027 elected to stagger its biennial reviews of utilities as provided in subdivision 1, under review ending later
 1028 than December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), the
 1029 Commission finds, with respect to such test period or periods considered as a whole, that (i) any utility
 1030 has, during the test period or periods under review, considered as a whole, earned more than 50 basis
 1031 points above a fair combined rate of return on its generation and distribution services or, for any test
 1032 period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a
 1033 Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and
 1034 distribution services, as determined in subdivision 2, without regard to any return on common equity or
 1035 other matters determined with respect to facilities described in subdivision 6, and (ii) the total aggregate
 1036 regulated rates of such utility at the end of the most recently ended 12-month test period exceeded the
 1037 annual increases in the United States Average Consumer Price Index for all items, all urban consumers
 1038 (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor,
 1039 compounded annually, when compared to the total aggregate regulated rates of such utility as
 1040 determined pursuant to the review conducted for the base period, the Commission shall, unless it finds
 1041 that such action is not in the public interest or that the provisions of subdivisions 8 b and c are more
 1042 consistent with the public interest, direct that any or all earnings for such test period or periods under
 1043 review, considered as a whole that were more than 50 basis points, or, for any test period commencing
 1044 after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more

1045 than 70 basis points, above such fair combined rate of return shall be credited to customers' bills, in lieu
1046 of the provisions of subdivisions 8 b and c, provided that no credits shall be provided pursuant to this
1047 subdivision in connection with any triennial review unless such bill credits would be payable pursuant to
1048 the provisions of subdivision 8 d, and any credits under this subdivision shall be calculated net of any
1049 customer credit reinvestment offset amounts under subdivision 8 d. Any such credits shall be amortized
1050 and allocated among customer classes in the manner provided by subdivision 8 b. For purposes of this
1051 subdivision:

1052 "Base period" means (i) the test period ending December 31, 2010 (or, if the Commission has elected
1053 to stagger its biennial reviews of utilities as provided in subdivision 1, the test period ending December
1054 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), or (ii) the most recent test
1055 period with respect to which credits have been applied to customers' bills under the provisions of this
1056 subdivision, whichever is later.

1057 "Total aggregate regulated rates" shall include: (i) fuel tariffs approved pursuant to § 56-249.6, except
1058 for any increases in fuel tariffs deferred by the Commission for recovery in periods after December 31,
1059 2010, pursuant to the provisions of clause (ii) of subsection C of § 56-249.6; (ii) rate adjustment clauses
1060 implemented pursuant to subdivision 4 or 5; (iii) revisions to the utility's rates pursuant to subdivision 8
1061 a; (iv) revisions to the utility's rates pursuant to the Commission's rules governing utility rate increase
1062 applications, as permitted by subsection B, occurring after July 1, 2009; and (v) base rates in effect as
1063 of July 1, 2009.

1064 10. For purposes of this section, the Commission shall regulate the rates, terms and conditions of any
1065 utility subject to this section on a stand-alone basis utilizing the actual end-of-test period capital
1066 structure and cost of capital of such utility, excluding any debt associated with securitized bonds that are
1067 the obligation of non-Virginia jurisdictional customers, unless the Commission finds that the debt to
1068 equity ratio of such capital structure is unreasonable for such utility, in which case the Commission may
1069 utilize a debt to equity ratio that it finds to be reasonable for such utility in determining any rate
1070 adjustment pursuant to subdivisions 8 a and c, and without regard to the cost of capital, capital structure,
1071 revenues, expenses or investments of any other entity with which such utility may be affiliated. In
1072 particular, and without limitation, the Commission shall determine the federal and state income tax costs
1073 for any such utility that is part of a publicly traded, consolidated group as follows: (i) such utility's
1074 apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the
1075 utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax
1076 costs shall be calculated according to the applicable federal income tax rate and shall exclude any
1077 consolidated tax liability or benefit adjustments originating from any taxable income or loss of its
1078 affiliates.

1079 B. Nothing in this section shall preclude an investor-owned incumbent electric utility from applying
1080 for an increase in rates pursuant to § 56-245 or the Commission's rules governing utility rate increase
1081 applications; however, in any such filing, a fair rate of return on common equity shall be determined
1082 pursuant to subdivision A 2. Nothing in this section shall preclude such utility's recovery of fuel and
1083 purchased power costs as provided in § 56-249.6.

1084 C. Except as otherwise provided in this section, the Commission shall exercise authority over the
1085 rates, terms and conditions of investor-owned incumbent electric utilities for the provision of generation,
1086 transmission and distribution services to retail customers in the Commonwealth pursuant to the
1087 provisions of Chapter 10 (§ 56-232 et seq.), including specifically § 56-235.2.

1088 D. The Commission may determine, during any proceeding authorized or required by this section, the
1089 reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection
1090 with the subject of the proceeding. A determination of the Commission regarding the reasonableness or
1091 prudence of any such cost shall be consistent with the Commission's authority to determine the
1092 reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ 56-232 et
1093 seq.). In determining the reasonableness or prudence of a utility providing energy and capacity to its
1094 customers from renewable energy resources, the Commission shall consider the extent to which such
1095 renewable energy resources, whether utility-owned or by contract, further the objectives of the
1096 Commonwealth Energy Policy set forth in §§ 67-101 and 67-102, and shall also consider whether the
1097 costs of such resources is likely to result in unreasonable increases in rates paid by customers.

1098 E. The Commission shall promulgate such rules and regulations as may be necessary to implement
1099 the provisions of this section.

1100 **§ 56-585.1:4. Development of solar and wind generation capacity and energy storage capacity in**
1101 **the Commonwealth.**

1102 A. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar
1103 or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic
1104 shoreline, each having a rated capacity of at least one megawatt and having in the aggregate a rated
1105 capacity that does not exceed 5,000 megawatts, or (ii) the purchase by a public utility of energy,
1106 capacity, and environmental attributes from solar facilities described in clause (i) owned by persons

1107 other than a public utility is in the public interest, and the Commission shall so find if required to make
1108 a finding regarding whether such construction or purchase is in the public interest.

1109 B. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar
1110 or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic
1111 shoreline, each having a rated capacity of less than one megawatt, including rooftop solar installations
1112 with a capacity of not less than 50 kilowatts, and having in the aggregate a rated capacity that does not
1113 exceed 500 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental
1114 attributes from solar facilities described in clause (i) owned by persons other than a public utility is in
1115 the public interest, and the Commission shall so find if required to make a finding regarding whether
1116 such construction or purchase is in the public interest.

1117 C. The aggregate cap of 5,000 megawatts of rated capacity described in clause (i) of subsection A
1118 and the aggregate cap of 500 megawatts of rated capacity described in clause (i) of subsection B are
1119 separate and independent from each other. The capacity of facilities in subsection B shall not be counted
1120 in determining the capacity of facilities in subsection A, and the capacity of facilities in subsection A
1121 shall not be counted in determining the capacity of facilities in subsection B.

1122 D. Twenty-five percent of the solar generation capacity placed in service on or after July 1, 2018,
1123 located in the Commonwealth, and found to be in the public interest pursuant to subsection A or B shall
1124 be from the purchase by a public utility of energy, capacity, and environmental attributes from solar
1125 facilities owned by persons other than a public utility. The remainder shall be construction or purchase
1126 by a public utility of one or more solar generation facilities located in the Commonwealth. All of the
1127 solar generation capacity located in the Commonwealth and found to be in the public interest pursuant
1128 to subsection A or B shall be subject to competitive procurement, provided that a public utility may
1129 select solar generation capacity without regard to whether such selection satisfies price criteria if the
1130 selection of the solar generating capacity materially advances non-price criteria, including favoring
1131 geographic distribution of generating capacity, areas of higher employment, or regional economic
1132 development, if such non-price solar generating capacity selected does not exceed 25 percent of the
1133 utility's solar generating capacity.

1134 E. Construction, purchasing, or leasing activities for a test or demonstration project for a new
1135 utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore
1136 wind with an aggregate capacity of not more than 16 megawatts are in the public interest.

1137 F. *Prior to January 1, 2035, (i) the construction by a public utility of one or more energy storage*
1138 *facilities located in the Commonwealth, having in the aggregate a rated capacity that does not exceed*
1139 *2,700 megawatts, or (ii) the purchase by a public utility of energy storage facilities described in clause*
1140 *(i) owned by persons other than a public utility or the capacity from such facilities is in the public*
1141 *interest, and the Commission shall so find if required to make a finding regarding whether such*
1142 *construction or purchase is in the public interest.*

1143 G. *At least 35 percent of the energy storage capacity placed in service on or after July 1, 2020,*
1144 *located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be*
1145 *from the purchase by a public utility of energy storage facilities owned by persons other than a public*
1146 *utility or the capacity from such facilities. All of the energy storage facilities located in the*
1147 *Commonwealth and found to be in the public interest pursuant to subsection F shall be subject to*
1148 *competitive procurement, provided that a public utility may select energy storage facilities without*
1149 *regard to whether such selection satisfies price criteria if the selection of the energy storage facilities*
1150 *materially advances non-price criteria, including favoring geographic distribution of generating*
1151 *facilities, areas of higher employment, or regional economic development, if such energy storage*
1152 *facilities selected for the advancement of non-price criteria do not exceed 25 percent of the utility's*
1153 *energy storage capacity.*

1154 H. A utility may elect to petition the Commission, outside of a triennial review proceeding conducted
1155 pursuant to § 56-585.1, at any time for a prudency determination with respect to the construction or
1156 purchase by the utility of one or more solar or wind generation facilities located in the Commonwealth
1157 or off the Commonwealth's Atlantic Shoreline or the purchase by the utility of energy, capacity, and
1158 environmental attributes from solar or wind facilities owned by persons other than the utility. The
1159 Commission's final order regarding any such petition shall be entered by the Commission not more than
1160 three months after the date of the filing of such petition.

1161 **§ 56-585.1:11. Development of offshore wind capacity.**

1162 A. *As used in this section:*

1163 "Advanced clean energy buyer" means a commercial or industrial customer of a Phase II Utility,
1164 irrespective of generation supplier, (i) with an aggregate load over 100 megawatts; (ii) with an
1165 aggregate amount of at least 200 megawatts of solar or wind energy supply under contract with a term
1166 of 10 years or more from facilities located within the Commonwealth by January 1, 2024; and (iii) that
1167 directly procures from the utility the electric supply and environmental attributes of the offshore wind

1168 facility associated with the lesser of 50 megawatts of nameplate capacity or 15 percent of the
1169 commercial or industrial customer's annual peak demand for a contract period of 15 years.

1170 "Aggregate load" means the combined electrical load associated with selected accounts of an
1171 advanced clean energy buyer with the same legal entity name as, or in the names of affiliated entities
1172 that control, are controlled by, or are under common control of, such legal entity or are the names of
1173 affiliated entities under a common parent.

1174 "Control" means the legal right, directly or indirectly, to direct or cause the direction of the
1175 management, actions, or policies of an affiliated entity, whether through the ability to exercise voting
1176 power, by contract, or otherwise. "Control" does not include control of an entity through a franchise or
1177 similar contractual agreement.

1178 "Qualifying large general service customer" means a customer of a Phase II Utility, irrespective of
1179 general supplier, (i) whose peak demand during the most recent calendar year exceeded five megawatts
1180 and (ii) that contracts with the utility to directly procure electric supply and environmental attributes
1181 associated with the offshore wind facility in amounts commensurate with the customer's electric usage
1182 for a contract period of 15 years or more.

1183 B. In order to meet the Commonwealth's clean energy goals, prior to December 31, 2034, the
1184 construction or purchase by a public utility of one or more offshore wind generation facilities located
1185 off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the
1186 Commonwealth, with an aggregate capacity of up to 5,200 megawatts, is in the public interest and the
1187 Commission shall so find, provided that no customers of the utility shall be responsible for costs of any
1188 such facility in a proportion greater than the utility's share of the facility.

1189 C. 1. Pursuant to subsection B, construction by a Phase II Utility of one or more new utility-owned
1190 and utility-operated generating facilities utilizing energy derived from offshore wind and located off the
1191 Commonwealth's Atlantic shoreline, with an aggregate rated capacity of not less than 2,500 megawatts
1192 and not more than 3,000 megawatts, along with electrical transmission or distribution facilities
1193 associated therewith for interconnection is in the public interest. In acting upon any request for cost
1194 recovery by a Phase II Utility for costs associated with such a facility, the Commission shall determine
1195 the reasonableness and prudence of any such costs, provided that such costs shall be presumed to be
1196 reasonably and prudently incurred if the Commission determines that (i) the utility has complied with
1197 the competitive solicitation and procurement requirements pursuant to subsection E; (ii) the project's
1198 projected total levelized cost of energy, including any tax credit, on a cost per megawatt hour basis,
1199 inclusive of the costs of transmission and distribution facilities associated with the facility's
1200 interconnection, does not exceed 1.4 times the comparable cost, on an unweighted average basis, of a
1201 conventional simple cycle combustion turbine generating facility as estimated by the U.S. Energy
1202 Information Administration in its Annual Energy Outlook 2019; and (iii) the utility has commenced
1203 construction of such facilities for U.S. income taxation purposes prior to January 1, 2024, or has a plan
1204 for such facility or facilities to be in service prior to January 1, 2028. The Commission shall disallow
1205 costs, or any portion thereof, only if they are otherwise unreasonably and imprudently incurred. In its
1206 review, the Commission shall give due consideration to (a) the Commonwealth's renewable portfolio
1207 standards and carbon reduction requirements, (b) the promotion of new renewable generation resources,
1208 and (c) the economic development benefits of the project for the Commonwealth, including capital
1209 investments and job creation.

1210 2. Notwithstanding the provisions of § 56-585.1, the Commission shall not grant an enhanced rate of
1211 return to a Phase II Utility for the construction of one or more new utility-owned and utility-operated
1212 generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's
1213 Atlantic shoreline pursuant to this section.

1214 3. Any such costs proposed for recovery through a rate adjustment clause pursuant to subdivision A
1215 6 of § 56-585.1 shall be allocated to all customers of the utility in the Commonwealth as a
1216 non-bypassable charge, regardless of the generation supplier of any such customer, other than (i) PIPP
1217 eligible utility customers, (ii) advanced clean energy buyers, and (iii) qualifying large general service
1218 customers. No electric cooperative customer of the utility shall be assigned, nor shall the utility collect
1219 from any such cooperative, any of the costs of such facilities, including electrical transmission or
1220 distribution facilities associated therewith for interconnection. The Commission may promulgate such
1221 rules, regulations, or other directives necessary to administer the eligibility for these exemptions.

1222 4. The Commission shall permit a portion of the nameplate capacity of any such facility, in the
1223 aggregate, to be allocated to (i) advanced clean energy buyers or (ii) qualifying large general service
1224 customers, provided that no more than 10 percent of the offshore wind facility's capacity is allocated to
1225 qualifying large general service customers. A Phase II Utility shall petition the Commission for approval
1226 of a special contract with any advanced clean energy buyer, or any special rate applicable to qualifying
1227 large general service customers, pursuant to § 56-235.2, no later than 15 months prior to the projected
1228 commercial operation date of the facility, and all customer enrollments associated with such special
1229 contracts or rates shall be completed prior to commercial operation of the facility. Any such special

1230 contract or rate may include provisions for leveled rates of service over the duration of the customer's
 1231 contracted agreement with the utility, and the Commission shall determine that such special contract or
 1232 rate is designed to hold nonparticipating customers harmless over its term in connection with any
 1233 petition for approval by the utility. The utility may petition for approval of such special contracts or
 1234 rates in connection with any petition for approval of a rate adjustment clause pursuant to subdivision A
 1235 6 of § 56-585.1 to recover the costs of the facility, and the Commission shall rule upon any such
 1236 petitions in its final order in such proceeding within nine months from the date of filing.

1237 D. In constructing any such facility contemplated in subsection B, the utility shall develop and submit
 1238 a plan to the Commission for review that includes the following considerations: (i) options for utilizing
 1239 local workers; (ii) the economic development benefits of the project for the Commonwealth, including
 1240 capital investments and job creation; (iii) consultation with the Commonwealth's Chief Workforce
 1241 Development Officer, the Chief Diversity, Equity, and Inclusion Officer, and the Virginia Economic
 1242 Development Partnership, on opportunities to advance the Commonwealth's workforce and economic
 1243 development goals, including furtherance of apprenticeship and other workforce training programs; and
 1244 (iv) giving priority to the hiring, apprenticeship, and training of veterans, as that term is defined in
 1245 § 2.2-2000.1, local workers, and workers from historically economically disadvantaged communities.

1246 E. Any project constructed or purchased pursuant to subsection B shall (i) be subject to competitive
 1247 procurement or solicitation for a substantial majority of the services and equipment, exclusive of
 1248 interconnection costs, associated with the facility's construction; (ii) involve at least one experienced
 1249 developer; and (iii) demonstrate the economic development benefits within the Commonwealth, including
 1250 capital investments and job creation. A utility may give appropriate consideration to suppliers and
 1251 developers that have demonstrated successful experience in offshore wind.

1252 F. Any project shall include an environmental and fisheries mitigation plan submitted to the
 1253 Commission for the construction and operation of such offshore wind facilities, provided that such plan
 1254 includes an explicit description of the best management practices the bidder will employ that considers
 1255 the latest science at the time the proposal is made to mitigate adverse impacts to wildlife, natural
 1256 resources, ecosystems, and traditional or existing water-dependent uses. The plan shall include a
 1257 summary of pre-construction assessment activities, consistent with federal requirements, to determine the
 1258 spatial and temporal presence and abundance of marine mammals, sea turtles, birds, and bats, in the
 1259 offshore wind lease area.

1260 **§ 56-585.5. Generation of electricity from renewable and zero carbon sources.**

1261 A. As used in this section:

1262 "Accelerated renewable energy buyer" means a commercial or industrial customer of a Phase I or
 1263 Phase II Utility, irrespective of generation supplier, with an aggregate load over 25 megawatts in the
 1264 prior calendar year, that enters into arrangements pursuant to subsection G, as certified by the
 1265 Commission.

1266 "Aggregate load" means the combined electrical load associated with selected accounts of an
 1267 accelerated renewable energy buyer with the same legal entity name as, or in the names of affiliated
 1268 entities that control, are controlled by, or are under common control of, such legal entity or are the
 1269 names of affiliated entities under a common parent.

1270 "Control" has the same meaning as provided in § 56-585.1:11.

1271 "Falling water" means hydroelectric resources, including run-of-river generation from a combined
 1272 pumped-storage and run-of-river facility. "Falling water" does not include electricity generated from
 1273 pumped storage facilities.

1274 "Low-income qualifying projects" means a project that provides a minimum of 50 percent of the
 1275 respective electric output to low-income utility customers as that term is defined in § 56-576.

1276 "Phase I Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

1277 "Phase II Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

1278 "Previously developed project site" means any property, including related buffer areas, if any, that
 1279 has been previously disturbed or developed for non-single-family residential, nonagricultural, or
 1280 nonsilvicultural use, regardless of whether such property currently is being used for any purpose.

1281 "Previously developed project site" includes a brownfield as defined in § 10.1-1230 or any parcel that
 1282 has been previously used (i) for a retail, commercial, or industrial purpose; (ii) as a parking lot; (iii) as
 1283 the site of a parking lot canopy or structure; (iv) for mining, which is any lands affected by coal mining
 1284 that took place before August 3, 1977, or any lands upon which extraction activities have been
 1285 permitted by the Department of Mines, Minerals and Energy under Title 45.1; (v) for quarrying; or (vi)
 1286 as a landfill.

1287 "Total electric energy" means total electric energy sold to retail customers in the Commonwealth
 1288 service territory of a Phase I or Phase II Utility, other than accelerated renewable energy buyers, by
 1289 the incumbent electric utility or other retail supplier of electric energy in the previous calendar year,
 1290 excluding an amount equivalent to the annual percentages of the electric energy that was supplied to

1291 such customer from nuclear generating plants located within the Commonwealth in the previous
1292 calendar year, provided such nuclear units were operating by July 1, 2020, or from any zero-carbon
1293 electric generating facilities not otherwise RPS eligible sources and placed into service in the
1294 Commonwealth after July 1, 2030.

1295 "Zero-carbon electricity" means electricity generated by any generating unit that does not emit
1296 carbon dioxide as a by-product of combusting fuel to generate electricity.

1297 B. 1. By December 31, 2024, except for any coal-fired electric generating units (i) jointly owned with
1298 a cooperative utility or (ii) owned and operated by a Phase II Utility located in the coalfield region of
1299 the Commonwealth that co-fires with biomass, any Phase I and Phase II Utility shall retire all
1300 generating units principally fueled by oil with a rated capacity in excess of 500 megawatts and all
1301 coal-fired electric generating units operating in the Commonwealth.

1302 2. By December 31, 2028, each Phase I and II Utility shall retire all biomass-fired electric
1303 generating units that do not co-fire with coal.

1304 3. By December 31, 2045, each Phase I and II Utility shall retire all other electric generating units
1305 located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate
1306 electricity.

1307 4. A Phase I or Phase II Utility may petition the Commission for relief from the requirements of this
1308 subsection on the basis that the requirement would threaten the reliability or security of electric service
1309 to customers. The Commission shall consider in-state and regional transmission entity resources and
1310 shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any
1311 such petition.

1312 C. Each Phase I and Phase II Utility shall participate in a renewable energy portfolio standard
1313 program (RPS Program) that establishes annual goals for the sale of renewable energy to all retail
1314 customers in the utility's service territory, other than accelerated renewable energy buyers pursuant to
1315 subsection G, regardless of whether such customers purchase electric supply service from the utility or
1316 from suppliers other than the utility. To comply with the RPS Program, each Phase I and Phase II
1317 Utility shall procure and retire Renewable Energy Certificates (RECs) originating from renewable
1318 energy standard eligible sources (RPS eligible sources). For purposes of complying with the RPS
1319 Program from 2021 to 2024, a Phase I and Phase II Utility may use RECs from any renewable energy
1320 facility, as defined in § 56-576, provided that such facilities are located in the Commonwealth or are
1321 physically located within the PJM Interconnection, LLC (PJM) region. However, at no time during this
1322 period or thereafter may any Phase I or Phase II Utility use RECs from (i) renewable thermal energy,
1323 (ii) renewable thermal energy equivalent, (iii) biomass-fired facilities that are outside the
1324 Commonwealth, or (iv) biomass-fired facilities operating in the Commonwealth as of January 1, 2020,
1325 that supply 10 percent or more of their annual net electrical generation to the electric grid or more
1326 than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to
1327 which the generating source is interconnected. From compliance year 2025 and all years after, each
1328 Phase I and Phase II Utility may only use RECs from RPS eligible sources for compliance with the RPS
1329 Program.

1330 In order to qualify as RPS eligible sources, such sources must be (a) electric-generating resources
1331 that generate electric energy derived from solar or wind located in the Commonwealth or off the
1332 Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the
1333 Commonwealth or physically located within the PJM region; (b) falling water resources located in the
1334 Commonwealth or physically located within the PJM region that were in operation as of January 1,
1335 2020, that are owned by a Phase I or Phase II Utility or for which a Phase I or Phase II Utility has
1336 entered into a contract prior to January 1, 2020, to purchase the energy, capacity, and renewable
1337 attributes of such falling water resources; (c) non-utility-owned resources from falling water that (1) are
1338 less than 65 megawatts, (2) began commercial operation after December 31, 1979, or (3) added
1339 incremental generation representing greater than 50 percent of the original nameplate capacity after
1340 December 31, 1979, provided that such resources are located in the Commonwealth or are physically
1341 located within the PJM region; (d) waste-to-energy or landfill gas-fired generating resources located in
1342 the Commonwealth and in operation as of January 1, 2020, provided that such resources do not use
1343 waste heat from fossil fuel combustion or forest or woody biomass as fuel; or (e) biomass-fired facilities
1344 in operation in the Commonwealth in operation as of January 1, 2020, that supply no more than 10
1345 percent of their annual net electrical generation to the electric grid or no more than 15 percent of their
1346 annual total useful energy to any entity other than the manufacturing facility to which the generating
1347 source is interconnected. Regardless of any future maintenance, expansion, or refurbishment activities,
1348 the total amount of RECs that may be sold by any RPS eligible source using biomass in any year shall
1349 be no more than the number of megawatt hours of electricity produced by that facility in 2019;
1350 however, in no year may any RPS eligible source using biomass sell RECs in excess of the actual
1351 megawatt-hours of electricity generated by such facility that year. In order to comply with the RPS
1352 Program, each Phase I and Phase II Utility may use and retire the environmental attributes associated

1353 with any existing owned or contracted solar, wind, or falling water electric generating resources in
 1354 operation, or proposed for operation, in the Commonwealth or physically located within the PJM
 1355 region, with such resource qualifying as a Commonwealth-located resource for purposes of this
 1356 subsection, as of January 1, 2020, provided such renewable attributes are verified as RECs consistent
 1357 with the PJM-EIS Generation Attribute Tracking System.

1358 The RPS Program requirements shall be a percentage of the total electric energy sold in the
 1359 previous calendar year and shall be implemented in accordance with the following schedule:

1360 Phase I Utilities		1360 Phase II Utilities		
1361	1362 Year	1362 RPS Program	1362 Year	1362 RPS Program
1363		1363 Requirement		1363 Requirement
1364	2021	6%	2021	14%
1365	2022	7%	2022	17%
1366	2023	8%	2023	20%
1367	2024	10%	2024	23%
1368	2025	14%	2025	26%
1369	2026	17%	2026	29%
1370	2027	20%	2027	32%
1371	2028	24%	2028	35%
1372	2029	27%	2029	38%
1373	2030	30%	2030	41%
1374	2031	33%	2031	45%
1375	2032	36%	2032	49%
1376	2033	39%	2033	52%
1377	2034	42%	2034	55%
1378	2035	45%	2035	59%
1379	2036	53%	2036	63%
1380	2037	53%	2037	67%
1381	2038	57%	2038	71%
1382	2039	61%	2039	75%
1383	2040	65%	2040	79%
1384	2041	68%	2041	83%
1385	2042	71%	2042	87%
1386	2043	74%	2043	91%
1387	2044	77%	2044	95%
1388	2045	80%	2045 and thereafter	100%
1389	2046	84%		
1390	2047	88%		
1391	2048	92%		
1392	2049	96%		
1393	2050 and thereafter	100%		

1394 A Phase II Utility shall meet one percent of the RPS Program requirements in any given compliance
 1395 year with solar, wind, or anaerobic digestion resources of one megawatt or less located in the
 1396 Commonwealth, with not more than 3,000 kilowatts at any single location or at contiguous locations
 1397 owned by the same entity or affiliated entities and, to the extent that low-income qualifying projects are
 1398 available, then no less than 25 percent of such one percent shall be composed of low-income qualifying
 1399 projects.

1400 Beginning with the 2025 compliance year and thereafter, at least 75 percent of all RECs used by a
 1401 Phase II Utility in a compliance period shall come from RPS eligible resources located in the
 1402 Commonwealth.

1403 Any Phase I or Phase II Utility may apply renewable energy sales achieved or RECs acquired in
 1404 excess of the sales requirement for that RPS Program to the sales requirements for RPS Program
 1405 requirements in the year in which it was generated and the five calendar years after the renewable
 1406 energy was generated or the RECs were created. To the extent that a Phase I or Phase II Utility
 1407 procures RECs for RPS Program compliance from resources the utility does not own, the utility shall be
 1408 entitled to recover the costs of such certificates, at its election pursuant to § 56-249.6 or subdivision A 5
 1409 d of § 56-585.1.

1410 D. Each Phase I or Phase II Utility shall petition the Commission for necessary approvals to
 1411 procure zero-carbon electricity generating capacity as set forth in this subsection and energy storage
 1412 resources as set forth in subsection E. To the extent that a Phase I or Phase II Utility constructs or
 1413 acquires new zero-carbon generating facilities or energy storage resources, the utility shall petition the
 1414 Commission for the recovery of the costs of such facilities, at the utility's election, either through its
 1415 rates for generation and distribution services or through a rate adjustment clause pursuant to
 1416 subdivision A 6 of § 56-585.1. All costs not sought for recovery through a rate adjustment clause

1417 pursuant to subdivision A 6 of § 56-585.1 associated with generating facilities provided by sunlight or
1418 onshore or offshore wind are also eligible to be applied by the utility as a customer credit reinvestment
1419 offset as provided in subdivision A 8 of § 56-585.1. Costs associated with the purchase of energy,
1420 capacity, or environmental attributes from facilities owned by the persons other than the utility required
1421 by the subsection shall be recovered by the utility either through its rates for generation and distribution
1422 services or pursuant to § 56-249.6.

1423 1. Each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire,
1424 or enter into agreements to purchase the energy, capacity, and environmental attributes of 600
1425 megawatts of generating capacity using energy derived from sunlight or onshore wind.

1426 a. By December 31, 2023, each Phase I Utility shall petition the Commission for necessary approvals
1427 to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental
1428 attributes of at least 200 megawatts of generating capacity located in the Commonwealth using energy
1429 derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be
1430 from the purchase of energy, capacity, and environmental attributes from solar or onshore wind
1431 facilities owned by persons other than the utility, with the remainder, in the aggregate, being from
1432 construction or acquisition by such Phase I Utility.

1433 b. By December 31, 2027, each Phase I Utility shall petition the Commission for necessary approvals
1434 to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental
1435 attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth
1436 using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity
1437 procured shall be from the purchase of energy, capacity, and environmental attributes from solar or
1438 onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate,
1439 being from construction or acquisition by such Phase I Utility.

1440 c. By December 31, 2030, each Phase I Utility shall petition the Commission for necessary approvals
1441 to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental
1442 attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth
1443 using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity
1444 procured shall be from the purchase of energy, capacity, and environmental attributes from solar or
1445 onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate,
1446 being from construction or acquisition by such Phase I Utility.

1447 d. Nothing in this subdivision 1 shall prohibit such Phase I Utility from constructing, acquiring, or
1448 entering into agreements to purchase the energy, capacity, and environmental attributes of more than
1449 600 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight
1450 or onshore wind, provided the utility receives approval from the Commission pursuant to §§ 56-580 and
1451 56-585.1.

1452 2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary
1453 approvals to (i) construct, acquire, or enter into agreements to purchase the energy, capacity, and
1454 environmental attributes of 16,100 megawatts of generating capacity located in the Commonwealth using
1455 energy derived from sunlight or onshore wind, which shall include 1,100 megawatts of solar generation
1456 of a nameplate capacity not to exceed three megawatts per individual project and 35 percent of such
1457 generating capacity procured shall be from the purchase of energy, capacity, and environmental
1458 attributes from solar facilities owned by persons other than a utility, including utility affiliates and
1459 deregulated affiliates and (ii) pursuant to § 56-585.1:11, construct or purchase one or more offshore
1460 wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and
1461 interconnected directly into the Commonwealth with an aggregate capacity of up to 5,200 megawatts. At
1462 least 200 megawatts of the 16,100 megawatts shall be placed on previously developed project sites.

1463 a. By December 31, 2024, each Phase II Utility shall petition the Commission for necessary
1464 approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and
1465 environmental attributes of at least 3,000 megawatts of generating capacity located in the
1466 Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating
1467 capacity procured shall be from the purchase of energy, capacity, and environmental attributes from
1468 solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the
1469 aggregate, being from construction or acquisition by such Phase II Utility.

1470 b. By December 31, 2027, each Phase II Utility shall petition the Commission for necessary
1471 approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and
1472 environmental attributes of at least 3,000 megawatts of additional generating capacity located in the
1473 Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating
1474 capacity procured shall be from the purchase of energy, capacity, and environmental attributes from
1475 solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the
1476 aggregate, being from construction or acquisition by such Phase II Utility.

1477 c. By December 31, 2030, each Phase II Utility shall petition the Commission for necessary
1478 approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and

1479 environmental attributes of at least 4,000 megawatts of additional generating capacity located in the
1480 Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating
1481 capacity procured shall be from the purchase of energy, capacity, and environmental attributes from
1482 solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the
1483 aggregate, being from construction or acquisition by such Phase II Utility.

1484 d. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary
1485 approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and
1486 environmental attributes of at least 6,100 megawatts of additional generating capacity located in the
1487 Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating
1488 capacity procured shall be from the purchase of energy, capacity, and environmental attributes from
1489 solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the
1490 aggregate, being from construction or acquisition by such Phase II Utility.

1491 e. Nothing in this subdivision 2 shall prohibit such Phase II Utility from constructing, acquiring, or
1492 entering into agreements to purchase the energy, capacity, and environmental attributes of more than
1493 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from
1494 sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to
1495 §§ 56-580 and 56-585.1.

1496 3. Nothing in this section shall prohibit a utility from petitioning the Commission to construct or
1497 acquire zero-carbon electricity or from entering into contracts to procure the energy, capacity, and
1498 environmental attributes of zero-carbon electricity generating resources in excess of the requirements in
1499 subsection B. The Commission shall determine whether to approve such petitions on a stand-alone basis
1500 pursuant to §§ 56-580 and 56-585.1, provided that the Commission's review shall also consider whether
1501 the proposed generating capacity (i) is necessary to meet the utility's native load, (ii) is likely to lower
1502 customer fuel costs, (iii) will provide economic development opportunities in the Commonwealth, and
1503 (iv) serves a need that cannot be more affordably met with demand-side or energy storage resources.

1504 Each Phase I and Phase II Utility shall, at least once every year, conduct a request for proposals for
1505 new solar and wind resources. Such requests shall quantify and describe the utility's need for energy,
1506 capacity, or renewable energy certificates. The requests for proposals shall be publicly announced and
1507 made available for public review on the utility's website at least 45 days prior to the closing of such
1508 request for proposals. The requests for proposals shall provide, at a minimum, the following
1509 information: (a) the size, type, and timing of resources for which the utility anticipates contracting; (b)
1510 any minimum thresholds that must be met by respondents; (c) major assumptions to be used by the
1511 utility in the bid evaluation process, including environmental emission standards; (d) detailed
1512 instructions for preparing bids so that bids can be evaluated on a consistent basis; (e) the preferred
1513 general location of additional capacity; and (f) specific information concerning the factors involved in
1514 determining the price and non-price criteria used for selecting winning bids. A utility may evaluate
1515 responses to requests for proposals based on any criteria that it deems reasonable but shall at a
1516 minimum consider the following in its selection process: (1) the status of a particular project's
1517 development; (2) the age of existing generation facilities; (3) the demonstrated financial viability of a
1518 project and the developer; (4) a developer's prior experience in the field; (5) the location and effect on
1519 the transmission grid of a generation facility; (6) benefits to the Commonwealth that are associated with
1520 particular projects, including regional economic development and the use of goods and services from
1521 Virginia businesses; and (7) the environmental impacts of particular resources, including impacts on air
1522 quality within the Commonwealth and the carbon intensity of the utility's generation portfolio.

1523 4. In connection with the requirements of this subsection, each Phase I and Phase II Utility shall,
1524 commencing in 2020 and concluding in 2035, submit annually a plan and petition for approval for the
1525 development of new solar and onshore wind generation capacity. Such plan shall reflect, in the
1526 aggregate and over its duration, the requirements of subsection D concerning the allocation percentages
1527 for construction or purchase of such capacity. Such petition shall contain any request for approval to
1528 construct such facilities pursuant to subsection D of § 56-580 and a request for approval or update of a
1529 rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 to recover the costs of such facilities.
1530 Such plan shall also include the utility's plan to meet the energy storage project targets of subsection E,
1531 including the goal of installing at least 10 percent of such energy storage projects behind the meter. In
1532 determining whether to approve the utility's plan and any associated petition requests, the Commission
1533 shall determine whether they are reasonable and prudent, and shall give due consideration to (i) the
1534 RPS and carbon dioxide reduction requirements in this section, (ii) the promotion of new renewable
1535 generation and energy storage resources within the Commonwealth, and associated economic
1536 development, and (iii) fuel savings projected to be achieved by the plan. Notwithstanding any other
1537 provision of this title, the Commission's final order regarding any such petition and associated requests
1538 shall be entered by the Commission not more than six months after the date of the filing of such
1539 petition.

1540 5. If, in any year, a Phase I or Phase II Utility is unable to meet the compliance obligation of the
1541 RPS Program requirements or if the cost of RECs necessary to comply with RPS Program requirements
1542 exceeds \$45 per megawatt hour, such supplier shall be obligated to make a deficiency payment equal to
1543 \$45 for each megawatt-hour shortfall for the year of noncompliance, except that the deficiency payment
1544 for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in the
1545 Commonwealth shall be \$75 per megawatts hour for resources one megawatt and lower. The amount of
1546 any deficiency payment shall increase by one percent annually after 2021. A Phase I or Phase II Utility
1547 shall be entitled to recover the costs of such payments as a cost of compliance with the requirements of
1548 this subsection pursuant to subdivision A 5 d of § 56-585.1. All proceeds from the deficiency payments
1549 shall be deposited into an interest-bearing account administered by the Department of Mines, Minerals
1550 and Energy. In administering this account, the Department of Mines, Minerals and Energy shall manage
1551 the account as follows: (i) 50 percent of total revenue shall be directed to job training programs in
1552 historically economically disadvantaged communities; (ii) 16 percent of total revenue shall be directed
1553 to energy efficiency measures for public facilities; (iii) 30 percent of total revenue shall be directed to
1554 renewable energy programs located in historically economically disadvantaged communities; and (iv)
1555 four percent of total revenue shall be directed to administrative costs.

1556 E. To enhance reliability and performance of the utility's generation and distribution system, each
1557 Phase I and Phase II Utility shall petition the Commission for necessary approvals to construct or
1558 acquire new, utility-owned energy storage resources.

1559 1. By December 31, 2035, each Phase I Utility shall petition the Commission for necessary approvals
1560 to construct or acquire 400 megawatts of energy storage capacity. Nothing in this subdivision shall
1561 prohibit a Phase I Utility from constructing or acquiring more than 400 megawatts of energy storage,
1562 provided that the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

1563 2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary
1564 approvals to construct or acquire 2,700 megawatts of energy storage capacity. Nothing in this
1565 subdivision shall prohibit a Phase II Utility from constructing or acquiring more than 2,700 megawatts
1566 of energy storage, provided that the utility receives approval from the Commission pursuant to
1567 §§ 56-580 and 56-585.1.

1568 3. No single energy storage project shall exceed 500 megawatts in size, except that a Phase II Utility
1569 may procure a single energy storage project up to 800 megawatts.

1570 4. All energy storage projects procured pursuant to this subsection shall meet the competitive
1571 procurement protocols established in subdivision D 3.

1572 5. After July 1, 2020, at least 35 percent of the energy storage facilities placed into service shall be
1573 (i) purchased by the public utility from a party other than the public utility or (ii) owned by a party
1574 other than a public utility, with the capacity from such facilities sold to the public utility. By January 1,
1575 2021, the Commission shall adopt regulations to achieve the deployment of energy storage for the
1576 Commonwealth required in subdivisions E 1 and 2, including regulations that set interim targets and
1577 update existing utility planning and procurement rules. The regulations shall include programs and
1578 mechanisms to deploy energy storage, including competitive solicitations, behind-the-meter incentives,
1579 non-wires alternatives programs, and peak demand reduction programs.

1580 F. All costs incurred by a Phase I or Phase II Utility related to compliance with the requirements of
1581 this section or pursuant to § 56-585.1:11, including (i) costs of generation facilities powered by sunlight
1582 or onshore or offshore wind, or energy storage facilities, that are constructed or acquired by a Phase I
1583 or Phase II Utility after July 1, 2020, (ii) costs of capacity, energy, or environmental attributes from
1584 generation facilities powered by sunlight or onshore or offshore wind, or falling water, or energy
1585 storage facilities purchased by the utility from persons other than the utility through agreements after
1586 July 1, 2020, and (iii) all other costs of compliance, including costs associated with the purchase of
1587 RECs associated with RPS Program requirements pursuant to this section shall be recovered from all
1588 retail customers in the service territory of a Phase I or Phase II Utility as a non-bypassable charge,
1589 irrespective of the generation supplier of such customer, except (a) as provided in subsection G for an
1590 accelerated renewable energy buyer or (b) as provided in subdivision C 3 of § 56-585.1:11, with respect
1591 to the costs of an offshore wind generation facility, for a PIPP eligible utility customer or an advanced
1592 clean energy buyer or qualifying large general service customer, as those terms are defined in
1593 § 56-585.11. If a Phase I or Phase II Utility serves customers in more than one jurisdiction, such utility
1594 shall recover all of the costs of compliance with the RPS Program requirements from its Virginia
1595 customers through the applicable cost recovery mechanism, and all associated energy, capacity, and
1596 environmental attributes shall be assigned to Virginia to the extent that such costs are requested but not
1597 recovered from any system customers outside the Commonwealth.

1598 By September 1, 2020, the Commission shall direct the initiation of a proceeding for each Phase I
1599 and Phase II Utility to review and determine the amount of such costs, net of benefits, that should be
1600 allocated to retail customers within the utility's service territory which have elected to receive electric
1601 supply service from a supplier of electric energy other than the utility, and shall direct that tariff

1602 provisions be implemented to recover those costs from such customers beginning no later than January
1603 1, 2021. Thereafter, such charges and tariff provisions shall be updated and trued up by the utility on
1604 an annual basis, subject to continuing review and approval by the Commission.

1605 G. 1. An accelerated renewable energy buyer may contract with a Phase I or Phase II Utility, or a
1606 person other than a Phase I or Phase II Utility, to obtain (i) RECs from RPS eligible resources or (ii)
1607 bundled capacity, energy, and RECs from solar or wind generation resources located within the PJM
1608 region and initially placed in commercial operation after January 1, 2015. Such an accelerated
1609 renewable energy buyer may offset all or a portion of its electric load for purposes of RPS compliance
1610 through such arrangements. An accelerated renewable energy buyer shall be exempt from the
1611 assignment of non-bypassable RPS compliance costs pursuant to subsection F, with the exception of the
1612 costs of an offshore wind generating facility pursuant to § 56-585.1:11, based on the amount of RECs
1613 obtained pursuant to this subsection in proportion to the customer's total electric energy consumption,
1614 on an annual basis, however, an accelerated renewable energy buyer obtaining RECs only shall not be
1615 exempt from costs related to procurement of new solar or onshore wind generation capacity, energy, or
1616 environmental attributes, or energy storage facilities by the utility pursuant to subsections D and E. To
1617 the extent that an accelerated renewable energy buyer contracts for the capacity of new solar or wind
1618 generation resources pursuant to this subsection, the aggregate amount of such nameplate capacity shall
1619 be offset from the utility's procurement requirements pursuant to subsection D. All RECs associated with
1620 contracts entered into by an accelerated renewable energy buyer with the utility, or a person other than
1621 the utility, for an RPS Program shall not be credited to the utility's compliance with its RPS
1622 requirements, and the calculation of the utility's RPS Program requirements shall not include the
1623 electric load covered by customers certified as accelerated renewable energy buyers.

1624 2. Each Phase I or Phase II Utility shall certify, and verify as necessary, to the Commission that the
1625 accelerated renewable energy buyer has satisfied the exemption requirements of this subsection for each
1626 year, or an accelerated renewable energy buyer may choose to certify satisfaction of this exemption by
1627 reporting to the Commission individually. The Commission may promulgate such rules and regulations
1628 as may be necessary to implement the provisions of this subsection.

1629 3. Provided that no incremental costs associated with any contract between a Phase I or Phase II
1630 Utility and an accelerated renewable energy buyer is allocated to or recovered from any other customer
1631 of the utility, any such contract with an accelerated renewable energy buyer that is a jurisdictional
1632 customer of the utility shall not be deemed a special rate or contract requiring Commission approval
1633 pursuant to § 56-235.2.

1634 H. No customer of a Phase II Utility with a peak demand in excess of 100 megawatts in 2019 that
1635 elected pursuant to subdivision A 3 of § 56-577 to purchase electric energy from a competitive service
1636 provider prior to April 1, 2019, shall be allocated any non-bypassable charges pursuant to subsection F
1637 for such period that the customer is not purchasing electric energy from the utility, and such customer's
1638 electric load shall not be included in the utility's RPS Program requirements. No customer of a Phase I
1639 Utility that elected pursuant to subdivision A 3 of § 56-577 to purchase electric energy from a
1640 competitive service provider prior to February 1, 2019, shall be allocated any non-bypassable charges
1641 pursuant to subsection F for such period that the customer is not purchasing electric energy from the
1642 utility, and such customer's electric load shall not be included in the utility's RPS Program
1643 requirements.

1644 I. Nothing in this section shall apply to any entity organized under Chapter 9.1 (§ 56-231.15 et seq.).

1645 J. The Commission shall adopt such rules and regulations as may be necessary to implement the
1646 provisions of this section, including a requirement that participants verify whether the RPS Program
1647 requirements are met in accordance with this section.

1648 **§ 56-585.6. Universal service fee; Percentage of Income Payment Program.**

1649 A. The Commission shall, after notice and opportunity for hearing, initiate a proceeding to establish
1650 the rates, terms, and conditions of a non-bypassable universal service fee to fund the Percentage of
1651 Income Payment Program (PIPP). Such universal service fee shall be allocated to retail electric
1652 customers of a Phase I and Phase II Utility on the basis of the amount of kilowatt-hours used and be
1653 established at such level to adequately address the PIPP's objectives to (i) reduce the energy burden of
1654 eligible participants by limiting electric bill payments directly to no more than six percent of the eligible
1655 participant's annual household income if the household's heating source is anything other than
1656 electricity, and to no more than ten percent of an eligible participant's annual household income on
1657 electricity costs if the household's heating source is electricity, and (ii) reduce the amount of electricity
1658 used by the eligible participant's household through participation in weatherization or energy efficiency
1659 programs and energy conservation education programs.

1660 B. The Commission shall determine the reasonable administrative costs for the investor-owned utility
1661 to collect the universal service fee and remit such funds to the Percentage of Income Payment Fund,
1662 and any other administrative costs the investor-owned utility may incur in complying with the PIPP, and

1663 shall determine the proper recovery mechanism for such costs. A Phase I and Phase II Utility shall not
 1664 be eligible to earn a rate of return on any equity or costs incurred to comply with the program
 1665 requirements or implementation.

1666 **§ 56-594. Net energy metering provisions.**

1667 A. The Commission shall establish by regulation a program that affords eligible customer-generators
 1668 the opportunity to participate in net energy metering, and a program, to begin no later than July 1, 2014,
 1669 for customers of investor-owned utilities and to begin no later than July 1, 2015, and to end July 1,
 1670 2019, for customers of electric cooperatives as provided in subsection G, to afford eligible agricultural
 1671 customer-generators the opportunity to participate in net energy metering. The regulations may include,
 1672 but need not be limited to, requirements for (i) retail sellers; (ii) owners or operators of distribution or
 1673 transmission facilities; (iii) providers of default service; (iv) eligible customer-generators; (v) eligible
 1674 agricultural customer-generators; or (vi) any combination of the foregoing, as the Commission
 1675 determines will facilitate the provision of net energy metering, provided that the Commission determines
 1676 that such requirements do not adversely affect the public interest. On and after July 1, 2017, small
 1677 agricultural generators or eligible agricultural customer-generators may elect to interconnect pursuant to
 1678 the provisions of this section or as small agricultural generators pursuant to § 56-594.2, but not both.
 1679 Existing eligible agricultural customer-generators may elect to become small agricultural generators, but
 1680 may not revert to being eligible agricultural customer-generators after such election. On and after July 1,
 1681 2019, interconnection of eligible agricultural customer-generators shall cease for electric cooperatives
 1682 only, and such facilities shall interconnect solely as small agricultural generators. For electric
 1683 cooperatives, eligible agricultural customer-generators whose renewable energy generating facilities were
 1684 interconnected before July 1, 2019, may continue to participate in net energy metering pursuant to this
 1685 section for a period not to exceed 25 years from the date of their renewable energy generating facility's
 1686 original interconnection.

1687 B. For the purpose of this section:

1688 "Eligible agricultural customer-generator" means a customer that operates a renewable energy
 1689 generating facility as part of an agricultural business, which generating facility (i) uses as its sole energy
 1690 source solar power, wind power, or aerobic or anaerobic digester gas, (ii) does not have an aggregate
 1691 generation capacity of more than 500 kilowatts, (iii) is located on land owned or controlled by the
 1692 agricultural business, (iv) is connected to the customer's wiring on the customer's side of its
 1693 interconnection with the distributor; (v) is interconnected and operated in parallel with an electric
 1694 company's transmission and distribution facilities, and (vi) is used primarily to provide energy to
 1695 metered accounts of the agricultural business. An eligible agricultural customer-generator may be served
 1696 by multiple meters that are located at separate but contiguous sites, such that the eligible agricultural
 1697 customer-generator may aggregate in a single account the electricity consumption and generation
 1698 measured by the meters, provided that the same utility serves all such meters. The aggregated load shall
 1699 be served under the appropriate tariff.

1700 "Eligible customer-generator" means a customer that owns and operates, or contracts with other
 1701 persons to own, operate, or both, an electrical generating facility that (i) has a capacity of not more than
 1702 ~~20~~ 25 kilowatts for residential customers and not more than ~~one megawatt~~ three megawatts for
 1703 nonresidential customers on an electrical generating facility placed in service after July 1, 2015; (ii) uses
 1704 as its total source of fuel renewable energy, as defined in § 56-576; (iii) is located on the customer's
 1705 premises and is connected to the customer's wiring on the customer's side of its interconnection with the
 1706 distributor; (iv) is interconnected and operated in parallel with an electric company's transmission and
 1707 distribution facilities; and (v) is intended primarily to offset all or part of the customer's own electricity
 1708 requirements. In addition to the electrical generating facility size limitations in clause (i), the capacity of
 1709 any generating facility installed under this section after July 1, 2015, shall not exceed the expected
 1710 annual energy consumption based on the previous 12 months of billing history or an annualized
 1711 calculation of billing history if 12 months of billing history is not available. *In addition to the electrical*
 1712 *generating facility size limitation in clause (i), in the certificated service territory of a Phase I Utility,*
 1713 *the capacity of any generating facility installed under this section after July 1, 2020, shall not exceed*
 1714 *100 percent of the expected annual energy consumption based on the previous 12 months of billing*
 1715 *history or an annualized calculation of billing history if 12 months of billing history is not available,*
 1716 *and in the certificated service territory of a Phase II Utility, the capacity of any generating facility*
 1717 *installed under this section after July 1, 2020, shall not exceed 150 percent of the expected annual*
 1718 *energy consumption based on the previous 12 months of billing history or an annualized calculation of*
 1719 *billing history if 12 months of billing history is not available.*

1720 "Net energy metering" means measuring the difference, over the net metering period, between (i)
 1721 electricity supplied to an eligible customer-generator or eligible agricultural customer-generator from the
 1722 electric grid and (ii) the electricity generated and fed back to the electric grid by the eligible
 1723 customer-generator or eligible agricultural customer-generator.

1724 "Net metering period" means the 12-month period following the date of final interconnection of the

1725 eligible customer-generator's or eligible agricultural customer-generator's system with an electric service
 1726 provider, and each 12-month period thereafter.

1727 "Small agricultural generator" has the same meaning that is ascribed to that term in § 56-594.2.

1728 C. The Commission's regulations shall ensure that (i) the metering equipment installed for net
 1729 metering shall be capable of measuring the flow of electricity in two directions and (ii) any eligible
 1730 customer-generator seeking to participate in net energy metering shall notify its supplier and receive
 1731 approval to interconnect prior to installation of an electrical generating facility. The electric distribution
 1732 company shall have 30 days from the date of notification for residential facilities, and 60 days from the
 1733 date of notification for nonresidential facilities, to determine whether the interconnection requirements
 1734 have been met. Such regulations shall allocate fairly the cost of such equipment and any necessary
 1735 interconnection. An eligible customer-generator's electrical generating system, and each electrical
 1736 generating system of an eligible agricultural customer-generator, shall meet all applicable safety and
 1737 performance standards established by the National Electrical Code, the Institute of Electrical and
 1738 Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories. Beyond the
 1739 requirements set forth in this section and to ensure public safety, power quality, and reliability of the
 1740 supplier's electric distribution system, an eligible customer-generator or eligible agricultural
 1741 customer-generator whose electrical generating system meets those standards and rules shall bear all
 1742 reasonable costs of equipment required for the interconnection to the supplier's electric distribution
 1743 system, including costs, if any, to (a) install additional controls, (b) perform or pay for additional tests,
 1744 and (c) purchase additional liability insurance.

1745 D. The Commission shall establish minimum requirements for contracts to be entered into by the
 1746 parties to net metering arrangements. Such requirements shall protect the eligible customer-generator or
 1747 eligible agricultural customer-generator against discrimination by virtue of its status as an eligible
 1748 customer-generator or eligible agricultural customer-generator, and permit customers that are served on
 1749 time-of-use tariffs that have electricity supply demand charges contained within the electricity supply
 1750 portion of the time-of-use tariffs to participate as an eligible customer-generator or eligible agricultural
 1751 customer-generator. Notwithstanding the cost allocation provisions of subsection C, eligible
 1752 customer-generators or eligible agricultural customer-generators served on demand charge-based
 1753 time-of-use tariffs shall bear the incremental metering costs required to net meter such customers.

1754 E. If electricity generated by an eligible customer-generator or eligible agricultural customer-generator
 1755 over the net metering period exceeds the electricity consumed by the eligible customer-generator or
 1756 eligible agricultural customer-generator, the customer-generator or eligible agricultural
 1757 customer-generator shall be compensated for the excess electricity if the entity contracting to receive
 1758 such electric energy and the eligible customer-generator or eligible agricultural customer-generator enter
 1759 into a power purchase agreement for such excess electricity. Upon the written request of the eligible
 1760 customer-generator or eligible agricultural customer-generator, the supplier that serves the eligible
 1761 customer-generator or eligible agricultural customer-generator shall enter into a power purchase
 1762 agreement with the requesting eligible customer-generator or eligible agricultural customer-generator that
 1763 is consistent with the minimum requirements for contracts established by the Commission pursuant to
 1764 subsection D. The power purchase agreement shall obligate the supplier to purchase such excess
 1765 electricity at the rate that is provided for such purchases in a net metering standard contract or tariff
 1766 approved by the Commission, unless the parties agree to a higher rate. The eligible customer-generator
 1767 or eligible agricultural customer-generator owns any renewable energy certificates associated with its
 1768 electrical generating facility; however, at the time that the eligible customer-generator or eligible
 1769 agricultural customer-generator enters into a power purchase agreement with its supplier, the eligible
 1770 customer-generator or eligible agricultural customer-generator shall have a one-time option to sell the
 1771 renewable energy certificates associated with such electrical generating facility to its supplier and be
 1772 compensated at an amount that is established by the Commission to reflect the value of such renewable
 1773 energy certificates. Nothing in this section shall prevent the eligible customer-generator or eligible
 1774 agricultural customer-generator and the supplier from voluntarily entering into an agreement for the sale
 1775 and purchase of excess electricity or renewable energy certificates at mutually-agreed upon prices if the
 1776 eligible customer-generator or eligible agricultural customer-generator does not exercise its option to sell
 1777 its renewable energy certificates to its supplier at Commission-approved prices at the time that the
 1778 eligible customer-generator or eligible agricultural customer-generator enters into a power purchase
 1779 agreement with its supplier. All costs incurred by the supplier to purchase excess electricity and
 1780 renewable energy certificates from eligible customer-generators or eligible agricultural
 1781 customer-generators shall be recoverable through its Renewable Energy Portfolio Standard (RPS) rate
 1782 adjustment clause, if the supplier has a Commission-approved RPS plan. If not, then all costs shall be
 1783 recoverable through the supplier's fuel adjustment clause. For purposes of this section, "all costs" shall
 1784 be defined as the rates paid to the eligible customer-generator or eligible agricultural customer-generator
 1785 for the purchase of excess electricity and renewable energy certificates and any administrative costs

1786 incurred to manage the eligible customer-generator's or eligible agricultural customer-generator's power
 1787 purchase arrangements. The net metering standard contract or tariff shall be available to eligible
 1788 customer-generators or eligible agricultural customer-generators on a first-come, first-served basis in
 1789 each electric distribution company's Virginia service area until the rated generating capacity owned and
 1790 operated by eligible customer-generators, eligible agricultural customer-generators, and small agricultural
 1791 generators in the Commonwealth reaches ~~one~~ *six percent, in the aggregate, five percent of which is*
 1792 *available to all customers and one percent of which is available only to low-income utility customers of*
 1793 *each electric distribution company's adjusted Virginia peak-load forecast for the previous year (the*
 1794 *systemwide cap), and shall require the supplier to pay the eligible customer-generator or eligible*
 1795 *agricultural customer-generator for such excess electricity in a timely manner at a rate to be established*
 1796 *by the Commission.*

1797 *On and after the earlier of (i) 2024 for a Phase I Utility or 2025 for a Phase II Utility or (ii) when*
 1798 *the aggregate rated generating capacity owned and operated by eligible customer-generators, eligible*
 1799 *agricultural customer-generators, and small agricultural generators in the Commonwealth reaches three*
 1800 *percent of a Phase I or Phase II Utility's adjusted Virginia peak-load forecast for the previous year, the*
 1801 *Commission shall conduct a net energy metering proceeding.*

1802 *In any net energy metering proceeding, the Commission shall, after notice and opportunity for*
 1803 *hearing, evaluate and establish (a) an amount customers shall pay on their utility bills each month for*
 1804 *the costs of using the utility's infrastructure; (b) an amount the utility shall pay to appropriately*
 1805 *compensate the customer, as determined by the Commission, for the total benefits such facilities provide;*
 1806 *(c) the direct and indirect economic impact of net metering to the Commonwealth; and (d) any other*
 1807 *information the Commission deems relevant. The Commission shall establish an appropriate rate*
 1808 *structure related thereto, which shall govern compensation related to all eligible customer-generators,*
 1809 *eligible agricultural customer-generators, and small agricultural generators, except low-income utility*
 1810 *customers, that interconnect after the effective date established in the Commission's final order. Nothing*
 1811 *in the Commission's final order shall affect any eligible customer-generators, eligible agricultural*
 1812 *customer-generators, and small agricultural generators who interconnect before the effective date of*
 1813 *such final order. As part of the net energy metering proceeding, the Commission shall evaluate the six*
 1814 *percent aggregate net metering cap and may, if appropriate, raise or remove such cap. The Commission*
 1815 *shall enter its final order in such a proceeding no later than 12 months after it commences such*
 1816 *proceeding, and such final order shall establish a date by which the new terms and conditions shall*
 1817 *apply for interconnection and shall also provide that, if the terms and conditions of compensation in the*
 1818 *final order differ from the terms and conditions available to customers before the proceeding,*
 1819 *low-income utility customers may interconnect under whichever terms are most favorable to them.*

1820 F. Any residential eligible customer-generator or eligible agricultural customer-generator who owns
 1821 and operates, or contracts with other persons to own, operate, or both, an electrical generating facility
 1822 with a capacity that exceeds ~~40~~ *15* kilowatts shall pay to its supplier, in addition to any other charges
 1823 authorized by law, a monthly standby charge. The amount of the standby charge and the terms and
 1824 conditions under which it is assessed shall be in accordance with a methodology developed by the
 1825 supplier and approved by the Commission. The Commission shall approve a supplier's proposed standby
 1826 charge methodology if it finds that the standby charges collected from all such eligible
 1827 customer-generators and eligible agricultural customer-generators allow the supplier to recover only the
 1828 portion of the supplier's infrastructure costs that are properly associated with serving such eligible
 1829 customer-generators or eligible agricultural customer-generators. Such an eligible customer-generator or
 1830 eligible agricultural customer-generator shall not be liable for a standby charge until the date specified in
 1831 an order of the Commission approving its supplier's methodology.

1832 G. On and after the later of July 1, 2019, or the effective date of regulations that the Commission is
 1833 required to adopt pursuant to § 56-594.01, (i) net energy metering in the service territory of each electric
 1834 cooperative shall be conducted as provided in a program implemented pursuant to § 56-594.01 and (ii)
 1835 the provisions of this section shall not apply to net energy metering in the service territory of an electric
 1836 cooperative except as provided in § 56-594.01.

1837 H. *The Commission may adopt such rules or establish such guidelines as may be necessary for its*
 1838 *general administration of this section.*

1839 *1. When the Commission conducts a net energy metering proceeding, it shall:*

1840 *1. Investigate and determine the costs and benefits of the current net energy metering program;*

1841 *2. Establish an appropriate netting measurement interval for a successor tariff that is just and*
 1842 *reasonable in light of the costs and benefits of the net metering program in aggregate, and applicable to*
 1843 *new requests for net energy metering service; and*

1844 *3. Determine a specific avoided cost for customer-generators, the different type of*
 1845 *customer-generator technologies where the Commission deems it appropriate, and establish the*
 1846 *methodology for determining the compensation rate for any net excess generation determined according*
 1847 *to the applicable net measurement interval for any new tariff.*

1848 *J. In evaluating the costs and benefits of the net energy metering program, the Commission shall*
 1849 *consider:*

1850 *1. The aggregate impact of customer-generators on the electric utility's long-run marginal costs of*
 1851 *generation, distribution, and transmission;*

1852 *2. The cost of service implications of customer-generators on other customers within the same class,*
 1853 *including an evaluation of whether customer-generators provide an adequate rate of return to the*
 1854 *electrical utility compared to the otherwise applicable rate class when, for analytical purposes only,*
 1855 *examined as a separate class within a cost of service study;*

1856 *3. The direct and indirect economic impact of the net energy metering program to the*
 1857 *Commonwealth; and*

1858 *4. Any other information it deems relevant, including environmental and resilience benefits of*
 1859 *customer-generator facilities.*

1860 **§ 56-596.2. Energy efficiency programs; financial assistance for low-income customers.**

1861 *Each Phase I Utility and Phase II Utility, as such terms are defined in subdivision A 1 of § 56-585.1,*
 1862 *A. Notwithstanding subsection G of § 56-580, or any other provision of law, each incumbent*
 1863 *investor-owned electric utility shall develop a proposed program of energy conservation measures*
 1864 *efficiency programs. Any program shall provide for the submission of a petition or petitions for approval*
 1865 *to design, implement, and operate energy efficiency programs pursuant to subdivision A 5 c of*
 1866 *§ 56-585.1. At least five 15 percent of such proposed costs of energy efficiency programs shall be*
 1867 *allocated to programs designed to benefit low-income, elderly, and or disabled individuals or veterans.*

1868 *B. Notwithstanding any other provision of law, each investor-owned incumbent electric utility shall*
 1869 *implement energy efficiency programs and measures to achieve the following total annual energy*
 1870 *savings:*

1871 *1. For Phase I electric utilities:*

1872 *a. In calendar year 2022, at least 0.5 percent of the average annual energy jurisdictional retail sales*
 1873 *by that utility in 2019;*

1874 *b. In calendar year 2023, at least 1.0 percent of the average annual energy jurisdictional retail sales*
 1875 *by that utility in 2019;*

1876 *c. In calendar year 2024, at least 1.5 percent of the average annual energy jurisdictional retail sales*
 1877 *by that utility in 2019; and*

1878 *d. In calendar year 2025, at least 2.0 percent of the average annual energy jurisdictional retail sales*
 1879 *by that utility in 2019;*

1880 *2. For Phase II electric utilities:*

1881 *a. In calendar year 2022, at least 1.25 percent of the average annual energy jurisdictional retail*
 1882 *sales by that utility in 2019;*

1883 *b. In calendar year 2023, at least 2.5 percent of the average annual energy jurisdictional retail sales*
 1884 *by that utility in 2019;*

1885 *c. In calendar year 2024, at least 3.75 percent of the average annual energy jurisdictional retail*
 1886 *sales by that utility in 2019; and*

1887 *d. In calendar year 2025, at least 5.0 percent of the average annual energy jurisdictional retail sales*
 1888 *by that utility in 2019; and*

1889 *3. For the time period 2026 through 2028, and for every successive three-year period thereafter, the*
 1890 *Commission shall establish new energy efficiency savings targets. In advance of the effective date of*
 1891 *such targets, the Commission shall, after notice and opportunity for hearing, initiate proceedings to*
 1892 *establish such targets. As part of such proceeding, the Commission shall consider the feasibility of*
 1893 *achieving energy efficiency goals and future energy efficiency savings through cost-effective programs*
 1894 *and measures. The Commission shall annually review the feasibility of the energy efficiency program*
 1895 *savings in this section and report to the Chairs of the House Committee on Labor and Commerce and*
 1896 *the Senate Committee on Commerce and Labor and the Secretary of Natural Resources and the*
 1897 *Secretary of Commerce and Trade on such feasibility by October 1, 2022, and each year thereafter.*

1898 *C. The projected costs for the utility to design, implement, and operate such energy efficiency*
 1899 *programs, including a margin to be recovered on operating expenses, shall be no less than an aggregate*
 1900 *amount of \$140 million for a Phase I Utility and \$870 million for a Phase II Utility for the period*
 1901 *beginning July 1, 2018, and ending July 1, 2028, including any existing approved energy efficiency*
 1902 *programs. In developing such portfolio of energy efficiency programs, each utility shall utilize a*
 1903 *stakeholder process, to be facilitated by an independent monitor compensated under the funding provided*
 1904 *pursuant to subdivision E of § 56-592.1, to provide input and feedback on (i) the development of such*
 1905 *energy efficiency programs and portfolios of programs; (ii) compliance with the total annual energy*
 1906 *savings set forth in this subsection and how such savings affect utility integrated resource plans; (iii)*
 1907 *recommended policy reforms by which the General Assembly or the Commission can ensure maximum*
 1908 *and cost-effective deployment of energy efficiency technology across the Commonwealth, and (iv) best*

1909 *practices for evaluation, measurement, and verification for the purposes of assessing compliance with*
 1910 *the total annual energy savings set forth in subsection B. Utilities shall utilize the services of a third*
 1911 *party to perform evaluation, measurement, and verification services to determine a utility's total annual*
 1912 *savings as required by this subsection, as well as the annual and lifecycle net and gross energy and*
 1913 *capacity savings, related emissions reductions, and other quantifiable benefits of each program; total*
 1914 *customer bill savings that the programs and portfolios produce; and utility spending on each program,*
 1915 *including any associated administrative costs. The third-party evaluator shall include and review each*
 1916 *utility's avoided costs and cost-benefit analyses. The findings and reports of such third parties shall be*
 1917 *concurrently provided to both the Commission and the utility, and the Commission shall make each such*
 1918 *final annual report easily and publicly accessible online. Such stakeholder process shall include the*
 1919 *participation of representatives from each utility, relevant directors, deputy directors, and staff members*
 1920 *of the State Corporation Commission who participate in approval and oversight of utility efficiency*
 1921 *programs, the office of Consumer Counsel of the Attorney General, the Department of Mines, Minerals*
 1922 *and Energy, energy efficiency program implementers, energy efficiency providers, residential and small*
 1923 *business customers, and any other interested stakeholder who the independent monitor deems appropriate*
 1924 *for inclusion in such process. The independent monitor shall convene meetings of the participants in the*
 1925 *stakeholder process not less frequently than twice in each calendar year during the period beginning July*
 1926 *1, 2019, and ending July 1, 2028. The independent monitor shall report on the status of the energy*
 1927 *efficiency stakeholder process, including (i) (a) the objectives established by the stakeholder group*
 1928 *during this process related to programs to be proposed, (ii) (b) recommendations related to programs to*
 1929 *be proposed that result from the stakeholder process, and (iii) (c) the status of those recommendations,*
 1930 *in addition to the petitions filed and the determination thereon, to the Governor, the State Corporation*
 1931 *Commission, and the Chairmen of the House Committee on Labor and Commerce and Senate Committee*
 1932 *on Commerce and Labor Committees on July 1, 2019, and annually thereafter through July 1, 2028.*

1933 *D. Nothing in this section shall apply to any entity organized under Chapter 9.1 (§ 56-231.15 et*
 1934 *seq.).*

1935 **2. That § 1 of the first enactment of Chapters 358 and 382 of the Acts of Assembly of 2013, as**
 1936 **amended by Chapter 803 of the Acts of Assembly of 2017, is amended and reenacted as follows:**

1937 § 1. That the State Corporation Commission (Commission) shall conduct pilot programs under which
 1938 a person that owns or operates a solar-powered or wind-powered electricity generation facility located on
 1939 premises owned or leased by an eligible customer-generator, as defined in § 56-594 of the Code of
 1940 Virginia, shall be permitted to sell the electricity generated from such facility exclusively to such
 1941 eligible customer-generator under a power purchase agreement used to provide third party financing of
 1942 the costs of such a renewable generation facility (third party power purchase agreement), subject to the
 1943 following terms, conditions, and restrictions:

1944 a. ~~A Notwithstanding subsection G of § 56-580 of the Code of Virginia or any other provision of~~
 1945 ~~law, a pilot program shall be conducted within the certificated service territory of each investor-owned~~
 1946 ~~electric utility other than a utility described in subsection G of § 56-580 of the Code of Virginia ("Pilot~~
 1947 ~~Utility"); provided that within the certificated service territory of an investor-owned utility that was not~~
 1948 ~~bound by a rate case settlement adopted by the Commission that extended in its application beyond~~
 1949 ~~January 1, 2002, nonprofit, private institutions of higher education as defined in § 23-1-100 of the Code~~
 1950 ~~of Virginia that are not being served by generation provided under subdivision A 5 of § 56-577 of the~~
 1951 ~~Code of Virginia shall be deemed to be customer-generators eligible to participate in the pilot program;~~

1952 b. The aggregated capacity of all generation facilities that are subject to such third party power
 1953 purchase agreements at any time during the pilot program shall not exceed ~~50~~ 500 megawatts for
 1954 *Virginia jurisdictional customers and 500 megawatts for Virginia nonjurisdictional customers* for an
 1955 investor-owned utility that was bound by a rate case settlement adopted by the Commission that
 1956 extended in its application beyond January 1, 2002, or ~~seven~~ 40 megawatts for an investor-owned utility
 1957 that was not bound by a rate case settlement adopted by the Commission that extended in its application
 1958 beyond January 1, 2002. Such limitation on the aggregated capacity of such facilities shall constitute a
 1959 portion of the existing limit of ~~one~~ six percent of each Pilot Utility's adjusted Virginia peak-load forecast
 1960 for the previous year that is available to eligible customer-generators pursuant to subsection E of
 1961 § 56-594 of the Code of Virginia. Notwithstanding any provision of this act that incorporates provisions
 1962 of § 56-594, the seller and the customer shall elect either to (i) enter into their third party power
 1963 purchase agreement subject to the conditions and provisions of the Pilot Utility's net energy metering
 1964 program under § 56-594 or (ii) provide that electricity generated from the generation facilities subject to
 1965 the third party power purchase agreement will not be net metered under § 56-594, provided that an
 1966 election not to net meter under § 56-594 shall not exempt the third party power purchase agreement and
 1967 the parties thereto from the requirements of this act that incorporate provisions of § 56-594;

1968 c. A solar-powered or wind-powered generation facility with a capacity of no less than 50 kilowatts
 1969 and no more than ~~one megawatt~~ three megawatts shall be eligible for a third party power purchase
 1970 agreement under ~~the~~ a pilot program; however, if the customer under such agreement is a low-income

1971 *utility customer, as defined in § 56-576 of the Code of Virginia or is an entity with tax-exempt status in*
 1972 *accordance with § 501(c) of the Internal Revenue Code of 1954, as amended, then such facility is*
 1973 *eligible for the pilot program even if it does not meet the 50 kilowatts minimum size requirement. The*
 1974 *maximum generation capacity of ~~one megawatt~~ three megawatts shall not affect the limits on the*
 1975 *capacity of electrical generating capacities of ~~20~~ 25 kilowatts for residential customers and 500 kilowatts*
 1976 *three megawatts for nonresidential customers set forth in subsection B of § 56-594 of the Code of*
 1977 *Virginia, which limitations shall continue to apply to net energy metering generation facilities regardless*
 1978 *of whether they are the subject of a third party power purchase agreement under the pilot program;*

1979 d. A generation facility that is the subject of a third party power purchase agreement under the pilot
 1980 program shall serve only one customer, and a third party power purchase agreement shall not serve
 1981 multiple customers;

1982 e. The customer under a third party power purchase agreement under the pilot program shall be
 1983 subject to the interconnection and other requirements imposed on eligible customer-generators pursuant
 1984 to subsection C of § 56-594 of the Code of Virginia, including the requirement that the customer bear
 1985 the reasonable costs, as determined by the Commission, of the items described in clauses (i), (ii), and
 1986 (iii) of such subsection;

1987 f. A third party power purchase agreement under the pilot program shall not be valid unless it
 1988 conforms in all respects to the requirements of the pilot program conducted under the provisions of this
 1989 act and unless the Commission and the Pilot Utility are provided written notice of the parties' intent to
 1990 enter into a third party power purchase agreement not less than 30 days prior to the agreement's
 1991 proposed effective date; and

1992 g. An affiliate of the Pilot Utility shall be permitted to offer and enter into third party power
 1993 purchase arrangements on the same basis as may any other person that satisfies the requirements of
 1994 being a seller under a third party power purchase agreement under the pilot program.

1995 **3. That § 56-585.2 of the Code of Virginia is repealed.**

1996 **4. That each investor-owned utility shall consult with the Clean Energy Advisory Board**
 1997 **established by Chapter 554 of the Acts of Assembly of 2019 in how best to inform low-income**
 1998 **customers of opportunities to lower electric bills through access to solar energy.**

1999 **5. That beginning September 1, 2022, and every three years thereafter, the Department of Mines,**
 2000 **Minerals and Energy, in consultation with the Council on Environmental Justice and appropriate**
 2001 **stakeholders, shall determine whether implementation of this act imposes a disproportionate**
 2002 **burden on historically economically disadvantaged communities, as defined in § 56-576 of the Code**
 2003 **of Virginia, as amended by this act, and shall report by January 1, 2023, and every three years**
 2004 **thereafter, to the Chairs of the House Committee on Labor and Commerce and the Senate**
 2005 **Committee on Commerce and Labor and to the Council on Environmental Justice.**

2006 **6. That in developing a plan to reduce carbon dioxide emissions from covered units described in**
 2007 **§ 10.1-1308 of the Code of Virginia, as amended by this act, the Secretary of Natural Resources**
 2008 **and the Secretary of Commerce and Trade, in consultation with the State Corporation**
 2009 **Commission and the Council on Environmental Justice and appropriate stakeholders, shall report**
 2010 **to the General Assembly by January 1, 2022, any recommendations on how to achieve 100 percent**
 2011 **carbon-free electric energy generation by 2045 at least cost for ratepayers. Such report shall**
 2012 **include a recommendation on whether the General Assembly should permanently repeal the ability**
 2013 **to obtain a certificate of public convenience and necessity for any electric generating unit that**
 2014 **emits carbon as a by-product of combusting fuel to generate electricity. Until the General**
 2015 **Assembly receives such report, the State Corporation Commission shall not issue a certificate of**
 2016 **public convenience and necessity for any investor-owned utility to own, operate, or construct any**
 2017 **electric generating unit that emits carbon as a by-product of combusting fuel to generate**
 2018 **electricity.**

2019 **7. That it shall be the policy of the Commonwealth that the State Corporation Commission,**
 2020 **Department of Mines, Minerals and Energy, and Virginia Council on Environmental Justice, in**
 2021 **the development of energy programs, job training programs, and placement of renewable energy**
 2022 **facilities, shall consider whether and how those facilities and programs benefit local workers,**
 2023 **historically economically disadvantaged communities, as defined in § 56-576 of the Code of**
 2024 **Virginia, as amended by this act, veterans, and individuals in the Virginia coalfield region that are**
 2025 **located near previously and presently permitted fossil fuel facilities or coal mines.**

2026 **8. That should the State Corporation Commission amend rules pursuant to the provisions of**
 2027 **§ 56-594 of the Code of Virginia, as amended by this act, it shall set forth rules for net energy**
 2028 **metering at electric cooperatives in a new and separate chapter of the Virginia Administrative**
 2029 **Code.**

2030 **9. That nothing in this act shall require the utilities or the State Corporation Commission to take**
 2031 **any action that, in the State Corporation Commission's discretion and after consideration of all**

2032 in-state and regional transmission entity resources, threatens the reliability or security of electric
2033 service to the utility's customers.

2034 10. That the investor-owned utility constructing a facility pursuant to § 56-585.1:11 of the Code of
2035 Virginia, as created by this act, shall provide the State Corporation Commission with reports on
2036 the facility's construction progress, including performance to construction timeline and budget, on
2037 no less than a quarterly basis throughout the construction period. The State Corporation
2038 Commission shall retain ongoing authority to review the reasonableness and prudence of any
2039 increases in the total projected cost of the RPS Program and the offshore wind facility during its
2040 construction period.

2041 11. That by January 1, 2028, if the Secretary of Natural Resources and the Secretary of
2042 Commerce and Trade (the Secretaries) determine that the greenhouse gas reduction targets are
2043 not met pursuant to § 10-1308 of the Code of Virginia, the Secretaries shall make a
2044 recommendation to the Chairs of the House Committee on Labor and Commerce and the Senate
2045 Committee on Commerce and Labor on the necessity and advisability of a moratorium on the
2046 issuance of permits for new fossil fuel-fired generating facilities by January 1, 2030.

2047 12. That the State Corporation Commission shall issue its final order in the Percentage of Income
2048 Payment Program (PIPP) proceeding established pursuant to § 56-585.6 of the Code of Virginia, as
2049 created by this act, by December 31, 2020, provided that the non-bypassable universal service fee
2050 shall not be collected from customers of a Phase I or a Phase II Utility, as those terms are defined
2051 in subdivision A 1 of § 56-585.1 of the Code of Virginia, as amended by this act, until such time as
2052 the PIPP is established. The Department of Housing and Community Development and the
2053 Department of Social Services shall convene a stakeholder working group and develop
2054 recommendations regarding the implementation of PIPP. Such recommendations shall allow for a
2055 utility to reimburse the administrative costs of the PIPP, not to exceed \$3 million, and shall be
2056 submitted to the Chairs of the House Committee on Labor and Commerce and the Senate
2057 Committee on Commerce and Labor by December 1, 2020.

2058 13. That this bill shall be referred to as the Virginia Clean Economy Act.