HB5673

LRB101 20817 JLS 70536 b

101ST GENERAL ASSEMBLY

State of Illinois

2019 and 2020

HB5673

by Rep. LaToya Greenwood

SYNOPSIS AS INTRODUCED:

See Index

Amends the Illinois Power Agency Act. For electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State: defines "energy efficiency"; in provisions concerning the renewable portfolio standards, specifies the goals for procurement of renewable energy credits and cost-effective renewable energy resources that shall be included in the long-term renewable resources procurement plan and makes other changes concerning these procurements; and provides for the calculation of the cost of equity for the purposes of recovering all reasonable and prudently incurred costs of energy efficiency measures from retail customers. Provides that savings of fuels other than electricity achieved by measures that educate about, incentivize, encourage or otherwise support the use of electricity to power vehicles shall count towards the applicable annual incremental goal and shall not be included in determining certain limits. Amends the Public Utilities Act. Provides that an electric utility that serves less than 3,000,000 retail customers but more than 500,000 customers in this State may plan for, construct, install, control, own, manage, or operate photovoltaic electricity production facilities and any energy storage facilities that are planned for, constructed, installed, controlled, owned, managed or operated in connection with photovoltaic electricity production facilities without obtaining a certificate of public convenience and necessity subject to specified terms and conditions. Defines "electric vehicle", "electric vehicle charging station", and "energy storage" for the purposes of the Electric Service Customer Choice and Rate Relief Law of 1997. Provides that, beginning in 2022, without obtaining any approvals from the Illinois Commerce Commission or any other agency, regardless of whether any such approval would otherwise be required, a participating utility that is a combination utility shall pay $1,000,000 per year for 10 years to the energy low-income and support program. Adds provisions authorizing certain utilities to plan for, construct, install, control, own, manage or operate electric vehicle charging infrastructure, including, but not limited to, electric vehicle charging stations within their service territories. Effective immediately.

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A BILL FOR

AN ACT concerning regulation.

Be it enacted by the People of the State of Illinois, represented in the General Assembly:

Section 1. Findings.

(a) Over the last decade, the General Assembly has empowered the State of Illinois to become a national leader in the implementation of a progressive energy policy. The General Assembly has enacted laws to increase investment in equitable energy efficiency, clean and renewable energy, and continued modernization of the electric grid. The General Assembly has further encouraged and enabled investment in the clean energy economy in Illinois to ensure that the State and its citizens, including low-income individuals, are equipped to enjoy the opportunities and benefits of a smart grid and smart metering infrastructure platform, adopt and deploy cost-effective distributed energy resource technologies and devices, and benefit from investments in job training and job creation. To ensure this progress can be sustained, the General Assembly finds and declares the following:

(1) The State of Illinois is a geographically large and diverse State and communities in central and southern Illinois have different strengths and needs than those in the northern region of the State.

(2) The changing energy marketplace is having a

measurable effect on employment, economic development, business growth, non-profit health, school funding, local government stability, and community development in central and southern Illinois, and updated policies are needed to address those impacts.

(3) The State should accelerate the development and adoption of technologies and facilities in central and southern Illinois so that there are greater opportunities for investment in clean energy, electric vehicles, energy storage facilities, management of peak load, and grid stability and reliability.

(4) Continuing the transparent, predictable, and accountable policy that allows electric utilities to undertake needed system investments and earn a fair return on their investments in an efficient manner is the best method for building a smart, reliable grid that is equipped for the clean energy future.

(b) The General Assembly therefore finds that it is necessary to develop an energy policy for central and southern Illinois that accelerates achievement of the State's renewable portfolio standard by creating new opportunities for investments in solar assets, building an electric vehicle charging infrastructure across hundreds of miles of roads, increasing research and deployment of new clean energy technology, and continuing to utilize transparent annual reviews to recover costs and set reasonable rates.

Section 5. The Illinois Power Agency Act is amended by changing Sections 1-10 and 1-75 as follows:

(20 ILCS 3855/1-10)

Sec. 1-10. Definitions.

"Agency" means the Illinois Power Agency.

"Agency loan agreement" means any agreement pursuant to which the Illinois Finance Authority agrees to loan the proceeds of revenue bonds issued with respect to a project to the Agency upon terms providing for loan repayment installments at least sufficient to pay when due all principal of, interest and premium, if any, on those revenue bonds, and providing for maintenance, insurance, and other matters in respect of the project.

"Authority" means the Illinois Finance Authority.

"Brownfield site photovoltaic project" means photovoltaics that are:

(1) interconnected to an electric utility as defined in this Section, a municipal utility as defined in this Section, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act; and

(2) located at a site that is regulated by any of the following entities under the following programs:

(A) the United States Environmental Protection

Agency under the federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended;

(B) the United States Environmental Protection Agency under the Corrective Action Program of the federal Resource Conservation and Recovery Act, as amended;

(C) the Illinois Environmental Protection Agency under the Illinois Site Remediation Program; or

(D) the Illinois Environmental Protection Agency under the Illinois Solid Waste Program.

"Clean coal facility" means an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon dioxide emissions at the following levels: at least 50% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016, at least 70% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017, and at least 90% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation after 2017. The power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit. All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content, unless the clean coal facility does not use gasification technology and was operating as a conventional coal-fired electric generating facility on June 1, 2009 (the effective date of Public Act 95-1027).

"Clean coal SNG brownfield facility" means a facility that (1) has commenced construction by July 1, 2015 on an urban brownfield site in a municipality with at least 1,000,000 residents; (2) uses a gasification process to produce substitute natural gas; (3) uses coal as at least 50% of the total feedstock over the term of any sourcing agreement with a utility and the remainder of the feedstock may be either petroleum coke or coal, with all such coal having a high bituminous rank and greater than 1.7 pounds of sulfur per million Btu content unless the facility reasonably determines that it is necessary to use additional petroleum coke to deliver additional consumer savings, in which case the facility shall use coal for at least 35% of the total feedstock over the term of any sourcing agreement; and (4) captures and sequesters at least 85% of the total carbon dioxide emissions that the facility would otherwise emit.

"Clean coal SNG facility" means a facility that uses a gasification process to produce substitute natural gas, that sequesters at least 90% of the total carbon dioxide emissions that the facility would otherwise emit, that uses at least 90% coal as a feedstock, with all such coal having a high bituminous rank and greater than 1.7 pounds of sulfur per million btu content, and that has a valid and effective permit to construct emission sources and air pollution control equipment and approval with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the plant pursuant to the federal Clean Air Act; provided, however, a clean coal SNG brownfield facility shall not be a clean coal SNG facility.

"Commission" means the Illinois Commerce Commission.

"Community renewable generation project" means an electric generating facility that:

(1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;

(2) is interconnected at the distribution system level of an electric utility as defined in this Section, a municipal utility as defined in this Section that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities

Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act;

(3) credits the value of electricity generated by the facility to the subscribers of the facility; and

(4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.

"Costs incurred in connection with the development and construction of a facility" means:

(1) the cost of acquisition of all real property, fixtures, and improvements in connection therewith and equipment, personal property, and other property, rights, and easements acquired that are deemed necessary for the operation and maintenance of the facility;

(2) financing costs with respect to bonds, notes, and other evidences of indebtedness of the Agency;

(3) all origination, commitment, utilization, facility, placement, underwriting, syndication, credit enhancement, and rating agency fees;

(4) engineering, design, procurement, consulting, legal, accounting, title insurance, survey, appraisal, escrow, trustee, collateral agency, interest rate hedging, interest rate swap, capitalized interest, contingency, as required by lenders, and other financing costs, and other expenses for professional services; and

(5) the costs of plans, specifications, site study and investigation, installation, surveys, other Agency costs

and estimates of costs, and other expenses necessary or incidental to determining the feasibility of any project, together with such other expenses as may be necessary or incidental to the financing, insuring, acquisition, and construction of a specific project and starting up, commissioning, and placing that project in operation.

"Delivery services" has the same definition as found in Section 16-102 of the Public Utilities Act.

"Delivery year" means the consecutive 12-month period beginning June 1 of a given year and ending May 31 of the following year.

"Department" means the Department of Commerce and Economic Opportunity.

"Director" means the Director of the Illinois Power Agency.

"Demand-response" means measures that decrease peak electricity demand or shift demand from peak to off-peak periods.

"Distributed renewable energy generation device" means a device that is:

(1) powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;

(2) interconnected at the distribution system level of either an electric utility as defined in this Section, a

municipal utility as defined in this Section that owns or operates electric distribution facilities, or a rural electric cooperative as defined in Section 3-119 of the Public Utilities Act;

(3) located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and

(4) limited in nameplate capacity to less than or equal to 2,000 kilowatts.

"Energy efficiency" means measures that reduce the amount of electricity or natural gas consumed in order to achieve a given end use. "Energy efficiency" includes voltage optimization measures that optimize the voltage at points on the electric distribution voltage system and thereby reduce electricity consumption by electric customers' end use devices. "Energy efficiency" also includes measures that reduce the total Btus of electricity, natural gas, and other fuels needed to meet the end use or uses. For electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, energy efficiency measures that reduce the total Btus of electricity, natural gas, or other fuels needed to meet the end use or uses, shall include, but are not limited to, measures that educate about, incentivize, encourage, or otherwise support the use of electricity to power, in whole or in part, vehicles, including, but not limited to, cars, trucks, buses, trains, trolleys, boats, on-road or off-road vehicles, or other equipment or methods of transporting goods or people, and such measures shall include, but are not limited to, measures that educate about, incentivize, encourage, or otherwise support the adoption of electric vehicles by retail customers of all customer classes.

"Electric utility" has the same definition as found in Section 16-102 of the Public Utilities Act.

"Facility" means an electric generating unit or a co-generating unit that produces electricity along with related equipment necessary to connect the facility to an electric transmission or distribution system.

"Governmental aggregator" means one or more units of local government that individually or collectively procure electricity to serve residential retail electrical loads located within its or their jurisdiction.

"Local government" means a unit of local government as defined in Section 1 of Article VII of the Illinois Constitution.

"Municipality" means a city, village, or incorporated town.

"Municipal utility" means a public utility owned and operated by any subdivision or municipal corporation of this State.

"Nameplate capacity" means the aggregate inverter nameplate capacity in kilowatts AC.

"Person" means any natural person, firm, partnership, corporation, either domestic or foreign, company, association, limited liability company, joint stock company, or association and includes any trustee, receiver, assignee, or personal representative thereof.

"Project" means the planning, bidding, and construction of a facility.

"Public utility" has the same definition as found in Section 3-105 of the Public Utilities Act.

"Real property" means any interest in land together with all structures, fixtures, and improvements thereon, including lands under water and riparian rights, any easements, covenants, licenses, leases, rights-of-way, uses, and other interests, together with any liens, judgments, mortgages, or other claims or security interests related to real property.

"Renewable energy credit" means a tradable credit that represents the environmental attributes of one megawatt hour of energy produced from a renewable energy resource.

"Renewable energy resources" includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. "Renewable energy resources" does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.

"Retail customer" has the same definition as found in Section 16-102 of the Public Utilities Act.

"Revenue bond" means any bond, note, or other evidence of indebtedness issued by the Authority, the principal and interest of which is payable solely from revenues or income derived from any project or activity of the Agency.

"Sequester" means permanent storage of carbon dioxide by injecting it into a saline aquifer, a depleted gas reservoir, or an oil reservoir, directly or through an enhanced oil recovery process that may involve intermediate storage, regardless of whether these activities are conducted by a clean coal facility, a clean coal SNG facility, a clean coal SNG brownfield facility, or a party with which a clean coal facility, clean coal SNG facility, or clean coal SNG brownfield facility has contracted for such purposes.

"Service area" has the same definition as found in Section 16-102 of the Public Utilities Act.

"Sourcing agreement" means (i) in the case of an electric utility, an agreement between the owner of a clean coal facility and such electric utility, which agreement shall have terms and conditions meeting the requirements of paragraph (3) of subsection (d) of Section 1-75, (ii) in the case of an alternative retail electric supplier, an agreement between the owner of a clean coal facility and such alternative retail electric supplier, which agreement shall have terms and conditions meeting the requirements of Section 16-115(d)(5) of the Public Utilities Act, and (iii) in case of a gas utility, an agreement between the owner of a clean coal SNG brownfield facility and the gas utility, which agreement shall have the terms and conditions meeting the requirements of subsection (h-1) of Section 9-220 of the Public Utilities Act.

"Subscriber" means a person who (i) takes delivery service from an electric utility, and (ii) has a subscription of no less than 200 watts to a community renewable generation project that is located in the electric utility's service area. No subscriber's subscriptions may total more than 40% of the nameplate capacity of an individual community renewable generation project. Entities that are affiliated by virtue of a common parent shall not represent multiple subscriptions that total more than 40% of the nameplate capacity of an individual community renewable generation project.

"Subscription" means an interest in a community renewable generation project expressed in kilowatts, which is sized primarily to offset part or all of the subscriber's electricity usage.

"Substitute natural gas" or "SNG" means a gas manufactured by gasification of hydrocarbon feedstock, which is substantially interchangeable in use and distribution with conventional natural gas.

"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures and including avoided costs associated with reduced use of natural gas or other fuels, avoided costs associated with reduced water consumption, and avoided costs associated with reduced operation and maintenance costs, as well as other quantifiable societal benefits, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program for supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases. In discounting future societal costs and benefits for the purpose of calculating net present values, a societal discount rate based on actual, long-term Treasury bond yields should be used. Notwithstanding anything to the contrary, the TRC test shall not include or take into account a calculation of market price suppression effects or demand reduction induced price effects.

"Utility-scale solar project" means an electric generating facility that:

(1) generates electricity using photovoltaic cells; and

(2) has a nameplate capacity that is greater than 2,000 kilowatts.

"Utility-scale wind project" means an electric generating facility that:

(1) generates electricity using wind; and

(2) has a nameplate capacity that is greater than 2,000 kilowatts.

"Zero emission credit" means a tradable credit that represents the environmental attributes of one megawatt hour of energy produced from a zero emission facility.

"Zero emission facility" means a facility that: (1) is fueled by nuclear power; and (2) is interconnected with PJM Interconnection, LLC or the Midcontinent Independent System

Operator, Inc., or their successors.
(Source: P.A. 98-90, eff. 7-15-13; 99-906, eff. 6-1-17.)

(20 ILCS 3855/1-75)

Sec. 1-75. Planning and Procurement Bureau. The Planning and Procurement Bureau has the following duties and responsibilities:

(a) The Planning and Procurement Bureau shall each year, beginning in 2008, develop procurement plans and conduct competitive procurement processes in accordance with the requirements of Section 16-111.5 of the Public Utilities Act for the eligible retail customers of electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois. Beginning with the delivery year commencing on June 1, 2017, the Planning and Procurement Bureau shall develop plans and processes for the procurement of zero emission credits from zero emission facilities in accordance with the requirements of subsection (d-5) of this Section. The Planning and Procurement Bureau shall also develop procurement plans and conduct competitive procurement processes in accordance with the requirements of Section 16-111.5 of the Public Utilities Act for the eligible retail customers of small multi-jurisdictional electric utilities that (i) on December 31, 2005 served less than 100,000 customers in Illinois and (ii) request a procurement plan for their Illinois jurisdictional load. This Section shall not apply to a small multi-jurisdictional utility until such time as a small multi-jurisdictional utility requests the Agency to prepare a procurement plan for their Illinois jurisdictional load. For the purposes of this Section, the term "eligible retail customers" has the same definition as found in Section 16-111.5(a) of the Public Utilities Act.

Beginning with the plan or plans to be implemented in the 2017 delivery year, the Agency shall no longer include the procurement of renewable energy resources in the annual procurement plans required by this subsection (a), except as provided in subsection (q) of Section 16-111.5 of the Public Utilities Act, and shall instead develop a long-term renewable resources procurement plan in accordance with subsection (c) of this Section and Section 16-111.5 of the Public Utilities Act.

(1) The Agency shall each year, beginning in 2008, as needed, issue a request for qualifications for experts or expert consulting firms to develop the procurement plans in accordance with Section 16-111.5 of the Public Utilities Act. In order to qualify an expert or expert consulting firm must have:

(A) direct previous experience assembling large-scale power supply plans or portfolios for end-use customers;

(B) an advanced degree in economics, mathematics, engineering, risk management, or a related area of study;

(C) 10 years of experience in the electricity sector, including managing supply risk;

(D) expertise in wholesale electricity market rules, including those established by the Federal Energy Regulatory Commission and regional transmission organizations;

(E) expertise in credit protocols and familiarity with contract protocols;

(F) adequate resources to perform and fulfill the required functions and responsibilities; and

(G) the absence of a conflict of interest and inappropriate bias for or against potential bidders or the affected electric utilities.

(2) The Agency shall each year, as needed, issue a request for qualifications for a procurement administrator to conduct the competitive procurement processes in accordance with Section 16-111.5 of the Public Utilities Act. In order to qualify an expert or expert consulting firm must have:

(A) direct previous experience administering a large-scale competitive procurement process;

(B) an advanced degree in economics, mathematics, engineering, or a related area of study;

(C) 10 years of experience in the electricity sector, including risk management experience;

(D) expertise in wholesale electricity market rules, including those established by the Federal Energy Regulatory Commission and regional transmission organizations;

(E) expertise in credit and contract protocols;

(F) adequate resources to perform and fulfill the required functions and responsibilities; and

(G) the absence of a conflict of interest and inappropriate bias for or against potential bidders or the affected electric utilities.

(3) The Agency shall provide affected utilities and other interested parties with the lists of qualified experts or expert consulting firms identified through the request for qualifications processes that are under consideration to develop the procurement plans and to serve as the procurement administrator. The Agency shall also provide each qualified expert's or expert consulting firm's response to the request for qualifications. All information provided under this subparagraph shall also be provided to the Commission. The Agency may provide by rule for fees associated with supplying the information to utilities and other interested parties. These parties shall, within 5 business days, notify the Agency in writing if they object to any experts or expert consulting firms on the lists. Objections shall be based on:

(A) failure to satisfy qualification criteria;

(B) identification of a conflict of interest; or

(C) evidence of inappropriate bias for or against potential bidders or the affected utilities.

The Agency shall remove experts or expert consulting firms from the lists within 10 days if there is a reasonable basis for an objection and provide the updated lists to the affected utilities and other interested parties. If the Agency fails to remove an expert or expert consulting firm from a list, an objecting party may seek review by the Commission within 5 days thereafter by filing a petition, and the Commission shall render a ruling on the petition within 10 days. There is no right of appeal of the Commission's ruling.

(4) The Agency shall issue requests for proposals to the qualified experts or expert consulting firms to develop a procurement plan for the affected utilities and to serve as procurement administrator.

(5) The Agency shall select an expert or expert consulting firm to develop procurement plans based on the proposals submitted and shall award contracts of up to 5 years to those selected.

(6) The Agency shall select an expert or expert consulting firm, with approval of the Commission, to serve as procurement administrator based on the proposals submitted. If the Commission rejects, within 5 days, the Agency's selection, the Agency shall submit another recommendation within 3 days based on the proposals

submitted. The Agency shall award a 5-year contract to the expert or expert consulting firm so selected with Commission approval.

(b) The experts or expert consulting firms retained by the Agency shall, as appropriate, prepare procurement plans, and conduct a competitive procurement process as prescribed in Section 16-111.5 of the Public Utilities Act, to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for eligible retail customers of electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in the State of Illinois, and for eligible Illinois retail customers of small multi-jurisdictional electric utilities that (i) on December 31, 2005 served less than 100,000 customers in Illinois and (ii) request a procurement plan for their Illinois jurisdictional load.

(c) Renewable portfolio standard.

(1)(A) The Agency shall develop a long-term renewable resources procurement plan that shall include procurement programs and competitive procurement events necessary to meet the goals set forth in this subsection (c). The initial long-term renewable resources procurement plan shall be released for comment no later than 160 days after June 1, 2017 (the effective date of Public Act 99-906). The Agency shall review, and may revise on an expedited basis, the long-term renewable resources procurement plan at least every 2 years, which shall be conducted in conjunction with the procurement plan under Section 16-111.5 of the Public Utilities Act to the extent practicable to minimize administrative expense. The long-term renewable resources procurement plans shall be subject to review and approval by the Commission under Section 16-111.5 of the Public Utilities Act.

(B) Subject to subparagraph (F) of this paragraph (1), for electric utilities that serve more than 3,000,000 retail customers in this State or less than 500,000 retail customers in this State, the long-term renewable resources procurement plan shall include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter and for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, the long-term renewable resources procurement plan shall include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year, and by at least 1.5% every year thereafter to at least 32.5% by the 2030 delivery year; and continuing at no less than 32.5% for each delivery year thereafter. In the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1), the long-term plan shall prioritize compliance with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) over the annual percentage targets described in this subparagraph (B).

For the delivery year beginning June 1, 2017, the procurement plan shall include cost-effective renewable energy resources equal to at least 13% of each utility's load for eligible retail customers and 13% of the applicable portion of each utility's load for retail customers who are not eligible retail customers, which applicable portion shall equal 50% of the utility's load for retail customers who are not eligible retail customers on February 28, 2017.

For the delivery year beginning June 1, 2018, the procurement plan shall include cost-effective renewable energy resources equal to at least 14.5% of each utility's load for eligible retail customers and 14.5% of the applicable portion of each utility's load for retail customers who are not eligible retail customers, which applicable portion shall equal 75% of the utility's load for retail customers who are not eligible retail customers on February 28, 2017.

For the delivery year beginning June 1, 2019, and for each year thereafter, the procurement plans shall include cost-effective renewable energy resources equal to a minimum percentage of each utility's load for all retail customers as follows: <u>for electric utilities that serve more than 3,000,000 retail customers in this State or less than 500,000 retail customers in this State,</u> 16% by June 1, 2019; increasing by 1.5% each year thereafter to 25% by June 1, 2025; and 25% by June 1, 2026 and each year thereafter <u>and for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, 16% by June 1, 2019; increasing by 1.5% each year thereafter to 32.5% by June 1, 2030; and 32.5% by June 1, 2031 and each year thereafter</u>.

For each delivery year, the Agency shall first recognize each utility's obligations for that delivery year under existing contracts. Any renewable energy credits under existing contracts, including renewable energy credits as part of renewable energy resources, shall be used to meet the goals set forth in this subsection (c) for the delivery year.

(C) Of the renewable energy credits procured under this subsection (c), at least 75% shall come from wind and photovoltaic projects. The long-term renewable resources procurement plan described in subparagraph (A) of this paragraph (1) shall include the procurement of renewable energy credits in amounts equal to at least the following:

(i) By the end of the 2020 delivery year:

At least 2,000,000 renewable energy credits for each delivery year shall come from new wind projects; and

At least 2,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects; of that amount, to the extent possible, the Agency shall procure: at least 50% from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy generation devices or community renewable generation projects; at least 40% from utility-scale solar projects; at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects; and the remainder shall be determined through the long-term planning process described in subparagraph (A) of this paragraph (1); however, if the long-term renewable resources procurement plan includes the procurement of more than 2,000,000 renewable energy credits from new photovoltaic projects, then the foregoing allocations of renewable energy credits from the program outlined in subparagraph (K) of this paragraph (1), utility-scale solar projects, and brownfield site photovoltaic projects that are not community renewable generation projects shall not apply to the portion of the renewable energy credits procured in excess of the 2,000,000 renewable energy credits procured on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State and the allocation of such procurement on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall instead be based on the mix that produces the lowest cost for the renewable energy credits procured.

(ii) By the end of the 2025 delivery year:

At least 3,000,000 renewable energy credits for each delivery year shall come from new wind projects; and

At least 3,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects; of that amount, to the extent possible, the Agency shall procure: at least 50% from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy devices or community renewable generation projects; at least 40% from utility-scale solar projects; at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects; and the remainder shall be determined through the long-term planning process described in subparagraph (A) of this paragraph (1); however, if the long-term renewable resources procurement plan includes the procurement of more than 3,000,000 renewable energy credits from new photovoltaic projects, then the foregoing allocations of renewable energy credits from the program outlined in subparagraph (K) of this paragraph (1), utility-scale solar projects, and brownfield site photovoltaic projects that are not community renewable generation projects shall not apply to the portion of the renewable energy credits procured in excess of the 3,000,000 renewable energy credits procured on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State and the allocation of such procurement on behalf of

<u>electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall instead be based on the mix that produced the lowest cost for the renewable energy credits procured</u>.

(iii) By the end of the 2030 delivery year:

At least 4,000,000 renewable energy credits for each delivery year shall come from new wind projects; and

At least 4,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects; of that amount, to the extent possible, the Agency shall procure: at least 50% from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy devices or community renewable generation projects; at least 40% from utility-scale solar projects; at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects; and the remainder shall be determined through the long-term planning process described in subparagraph (A) of this paragraph (1)<u>; however, if the long-term renewable resources procurement plan includes the procurement of more than 4,000,000 renewable</u>

energy credits from new photovoltaic projects, then the foregoing allocations of renewable energy credits from the program outlined in subparagraph (K) of this paragraph (1), utility-scale solar projects, and brownfield site photovoltaic projects that are not community renewable generation projects shall not apply to the portion of the renewable energy credits procured in excess of the 4,000,000 renewable energy credits procured on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State and the allocation of such procurement on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall instead be based on the mix that produced the lowest cost for the renewable energy credits procured.

For purposes of this Section:

"New wind projects" means wind renewable energy facilities that are energized after June 1, 2017 for the delivery year commencing June 1, 2017 or within 3 years after the date the Commission approves contracts for subsequent delivery years.

"New photovoltaic projects" means photovoltaic renewable energy facilities that are energized after June 1, 2017. Photovoltaic projects developed under Section 1-56 of this Act shall not apply towards the new photovoltaic project requirements in this subparagraph (C).

(D) Renewable energy credits shall be cost effective. For purposes of this subsection (c), "cost effective" means that the costs of procuring renewable energy resources do not cause the limit stated in subparagraph (E) of this paragraph (1) to be exceeded and, for renewable energy credits procured through a competitive procurement event, do not exceed benchmarks based on market prices for like products in the region. For purposes of this subsection (c), "like products" means contracts for renewable energy credits from the same or substantially similar technology, same or substantially similar vintage (new or existing), the same or substantially similar quantity, and the same or substantially similar contract length and structure. Benchmarks shall be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval. If price benchmarks for like products in the region are not available, the procurement administrator shall establish price benchmarks based on publicly available data on regional technology costs and expected current and future regional energy prices. The benchmarks in this Section shall not be used to curtail or otherwise reduce contractual obligations entered into by or through the Agency prior to June 1, 2017 (the effective date of Public Act 99-906).

(E) For purposes of this subsection (c), the required procurement of cost-effective renewable energy resources for a particular year commencing prior to June 1, 2017 shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the delivery year ending immediately prior to the procurement, and, for delivery years commencing on and after June 1, 2017, the required procurement of cost-effective renewable energy resources for a particular year shall be measured as a percentage of the actual amount of electricity (megawatt-hours) delivered by the electric utility in the delivery year ending immediately prior to the procurement, to all retail customers in its service territory. For purposes of this subsection (c), the amount paid per kilowatthour means the total amount paid for electric service expressed on a per kilowatthour basis. For purposes of this subsection (c), the total amount paid for electric service includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes.

Notwithstanding the requirements of this subsection (c), the total of renewable energy resources procured under the procurement plan for any single year shall be subject to the limitations of this subparagraph (E). Such procurement shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011<u>; however, procurements that occur for procurement periods that begin on or after June 1, 2026 shall be reduced for all retail customers of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State only by an amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.515% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011</u>. To arrive at a maximum dollar amount of renewable energy resources to be procured for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered, or applicable portion of such amount as specified in paragraph (1) of this subsection (c), as applicable, by the electric utility in the delivery year immediately prior to the procurement to all retail customers in its service territory. The calculations required by this subparagraph (E) shall be made only once for each delivery year at the time that the renewable energy resources are procured. Once the determination as to the amount of renewable energy resources to procure is made based on the calculations set forth in this subparagraph (E) and the contracts procuring those amounts are executed, no subsequent rate impact determinations shall be made and no adjustments to those contract amounts shall be allowed. All costs incurred under such contracts shall be fully recoverable by the electric utility as provided in this Section.

(F) If the limitation on the amount of renewable energy resources procured in subparagraph (E) of this paragraph (1) prevents the Agency from meeting all of the goals in this subsection (c), the Agency's long-term plan shall prioritize compliance with the requirements of this subsection (c) regarding renewable energy credits in the following order:

(i) renewable energy credits under existing contractual obligations;

(i-5) funding for the Illinois Solar for All Program, as described in subparagraph (O) of this paragraph (1);

(ii) renewable energy credits necessary to comply with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1); and

(iii) renewable energy credits necessary to meet the remaining requirements of this subsection (c).

(G) The following provisions shall apply to the Agency's procurement of renewable energy credits under this subsection (c):

(i) Notwithstanding whether a long-term renewable resources procurement plan has been approved, the Agency shall conduct an initial forward procurement for renewable energy credits from new utility-scale wind projects within 160 days after June 1, 2017 (the effective date of Public Act 99-906). For the purposes of this initial forward procurement, the Agency shall solicit 15-year contracts for delivery of 1,000,000 renewable energy credits delivered annually from new utility-scale wind projects to begin delivery on June 1, 2019, if available, but not later than June 1, 2021, unless the project has delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract, in which case, not later than June 1, 2022. Payments to suppliers of renewable energy credits shall commence upon delivery. Renewable energy credits procured under this initial procurement shall be included in the Agency's long-term plan and shall apply to all renewable energy goals in this subsection (c).

(ii) Notwithstanding whether a long-term renewable resources procurement plan has been approved, the Agency shall conduct an initial forward procurement for renewable energy credits from new utility-scale solar projects and brownfield site photovoltaic projects within one year after June 1, 2017 (the effective date of Public Act 99-906). For the purposes of this initial forward procurement, the Agency shall solicit 15-year contracts for delivery of 1,000,000 renewable energy credits delivered annually from new utility-scale solar projects and brownfield site photovoltaic projects to begin delivery on June 1, 2019, if available, but not later than June 1, 2021, unless the project has delays in the establishment of an operating interconnection with the applicable transmission or distribution system as a result of the actions or inactions of the transmission or distribution provider, or other causes for force majeure as outlined in the procurement contract, in which case, not later than June 1, 2022. The Agency may structure this initial procurement in one or more discrete procurement events. Payments to suppliers of renewable energy credits shall commence upon delivery. Renewable energy credits procured under this initial procurement shall be included in the Agency's long-term plan and shall apply to all renewable energy goals in this subsection (c).

(iii) Subsequent forward procurements for utility-scale wind projects shall solicit at least 1,000,000 renewable energy credits delivered annually per procurement event and shall be planned, scheduled, and designed such that the cumulative amount of renewable energy credits delivered from all new wind projects in each delivery year shall not exceed the Agency's projection of the cumulative amount of renewable energy credits that will be delivered from all new photovoltaic projects, including utility-scale and distributed photovoltaic devices, in the same delivery year at the time scheduled for wind contract delivery.

(iv) If, at any time after the time set for delivery of renewable energy credits pursuant to the initial procurements in items (i) and (ii) of this subparagraph (G), the cumulative amount of renewable energy credits projected to be delivered from all new wind projects in a given delivery year exceeds the cumulative amount of renewable energy credits projected to be delivered from all new photovoltaic projects in that delivery year by 200,000 or more renewable energy credits, then the Agency shall within 60 days adjust the procurement programs in the long-term renewable resources procurement plan to ensure that the projected cumulative amount of renewable energy credits to be delivered from all new wind projects does not exceed the projected cumulative amount of renewable energy credits to be delivered from all new photovoltaic projects by 200,000 or more renewable energy credits, provided that nothing in this Section shall preclude the projected cumulative amount of renewable energy credits to be delivered from all new photovoltaic projects from exceeding the projected cumulative amount of renewable energy credits to be delivered from all new wind projects in each delivery year and provided further that nothing in this item (iv) shall require the curtailment of an executed contract. The Agency shall update, on a quarterly basis, its projection of the renewable energy credits to be delivered from all projects in each delivery year. Notwithstanding anything to the contrary, the Agency may adjust the timing of procurement events conducted under this subparagraph (G). The long-term renewable resources procurement plan shall set forth the process by which the adjustments may be made.

(v) All procurements under this subparagraph (G) shall comply with the geographic requirements in subparagraph (I) of this paragraph (1) and shall follow the procurement processes and procedures described in this Section and Section 16-111.5 of the Public Utilities Act to the extent practicable, and these processes and procedures may be expedited to accommodate the schedule established by this subparagraph (G).

(H) The procurement of renewable energy resources for a given delivery year shall be reduced as described in this subparagraph (H) if an alternative retail electric supplier meets the requirements described in this subparagraph (H).

(i) Within 45 days after June 1, 2017 (the effective date of Public Act 99-906), an alternative retail electric supplier or its successor shall submit an informational filing to the Illinois Commerce Commission certifying that, as of December 31, 2015, the alternative retail electric supplier owned one or more electric generating facilities that generates renewable energy resources as defined in Section 1-10 of this Act, provided that such facilities are not powered by wind or photovoltaics, and the facilities generate one renewable energy credit for each megawatthour of energy produced from the facility.

The informational filing shall identify each facility that was eligible to satisfy the alternative retail electric supplier's obligations under Section 16-115D of the Public Utilities Act as described in this item (i).

(ii) For a given delivery year, the alternative retail electric supplier may elect to supply its retail customers with renewable energy credits from the facility or facilities described in item (i) of this subparagraph (H) that continue to be owned by the alternative retail electric supplier.

(iii) The alternative retail electric supplier shall notify the Agency and the applicable utility, no later than February 28 of the year preceding the applicable delivery year or 15 days after June 1, 2017 (the effective date of Public Act 99-906), whichever is later, of its election under item (ii) of this subparagraph (H) to supply renewable energy credits to retail customers of the utility. Such election shall identify the amount of renewable energy credits to be supplied by the alternative retail electric supplier to the utility's retail customers and the source of the renewable energy credits identified in the informational filing as described in item (i) of this subparagraph (H), subject to the following limitations:

For the delivery year beginning June 1, 2018, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 25% multiplied by 14.5% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016.

For delivery years beginning June 1, 2019 and each year thereafter, the maximum amount of renewable energy credits to be supplied by an alternative retail electric supplier under this subparagraph (H) shall be 68% multiplied by 50% multiplied by 16% multiplied by the amount of metered electricity (megawatt-hours) delivered by the alternative retail electric supplier to Illinois retail customers during the delivery year ending May 31, 2016, provided that the 16% value shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.

For each delivery year, the total amount of renewable energy credits supplied by all alternative retail electric suppliers under this subparagraph (H) shall not exceed 9% of the Illinois target renewable energy credit quantity. The Illinois target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered in the delivery year immediately preceding that delivery year, provided that the 14.5% shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.

If the requirements set forth in items (i) through (iii) of this subparagraph (H) are met, the charges that would otherwise be applicable to the retail customers of the alternative retail electric supplier under paragraph (6) of this subsection (c) for the applicable delivery year shall be reduced by the ratio of the quantity of renewable energy credits supplied by the alternative retail electric supplier compared to that supplier's target renewable energy credit quantity. The supplier's target renewable energy credit quantity for the delivery year beginning June 1, 2018 is 14.5% multiplied by the total amount of metered electricity (megawatt-hours) delivered by the alternative retail supplier in that delivery year, provided that the 14.5% shall increase by 1.5% each delivery year thereafter to 25% by the delivery year beginning June 1, 2025, and thereafter the 25% value shall apply to each delivery year.

On or before April 1 of each year, the Agency shall annually publish a report on its website that identifies the aggregate amount of renewable energy credits supplied by alternative retail electric suppliers under this subparagraph (H).

(I) The Agency shall design its long-term renewable energy procurement plan to maximize the State's interest in the health, safety, and welfare of its residents, including but not limited to minimizing sulfur dioxide, nitrogen oxide, particulate matter and other pollution that adversely affects public health in this State, increasing fuel and resource diversity in this State, enhancing the reliability and resiliency of the electricity distribution system in this State, meeting goals to limit carbon dioxide emissions under federal or State law, and contributing to a cleaner and healthier environment for the citizens of this State, while balancing these goals with the requirement to minimize the cost to customers attributable to the procurement of renewable energy credits set forth in subparagraph (C) of paragraph (1) of this subsection (c). In order to further these legislative purposes, renewable energy credits shall be eligible to be counted toward the renewable energy requirements of this subsection (c) if they are generated from facilities located in this State. The Agency may qualify renewable energy credits from facilities located in states adjacent to Illinois if the generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents based on the public interest criteria described above. To ensure that the public interest criteria are applied to the procurement and given full effect, the Agency's long-term procurement plan shall describe in detail how each public interest factor shall be considered and weighted for facilities located in states adjacent to Illinois.

(J) In order to promote the competitive development of renewable energy resources in furtherance of the State's interest in the health, safety, and welfare of its residents, renewable energy credits shall not be eligible to be counted toward the renewable energy requirements of this subsection (c) if they are sourced from a generating unit whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017. Each contract executed to purchase renewable energy credits under this subsection (c) shall provide for the contract's termination if the costs of the generating unit supplying the renewable energy credits subsequently begin to be recovered through rates regulated by this State or any other state or states; and each contract shall further provide that, in that event, the supplier of the credits must return 110% of all payments received under the contract. Amounts returned under the requirements of this subparagraph (J) shall be retained by the utility and all of these amounts shall be used for the procurement of additional renewable energy credits from new wind or new photovoltaic resources as defined in this subsection (c). The long-term plan shall provide that these renewable energy credits shall be procured in the next procurement event.

Notwithstanding the limitations of this subparagraph (J), renewable energy credits sourced from generating units that are constructed, purchased, owned, or leased by an electric utility as part of an approved project, program, or pilot under Section 1-56 of this Act shall be eligible to be counted toward the renewable energy requirements of this subsection (c), regardless of how the costs of these units are recovered.

(K) The long-term renewable resources procurement plan developed by the Agency in accordance with subparagraph (A) of this paragraph (1) shall include an Adjustable Block program for the procurement of renewable energy credits from new photovoltaic projects that are distributed renewable energy generation devices or new photovoltaic community renewable generation projects on behalf of electric utilities that serve more than 3,000,000 retail customers or less than 500,000 retail customers in this State and a competitive procurement process for the procurement of new photovoltaic community renewable generation projects on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State. The Adjustable Block program shall be designed to provide a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time. The prices set by the Adjustable Block program can be reflected as a set value or as the product of a formula.

The Adjustable Block program shall include for each category of eligible projects: a schedule of standard block purchase prices to be offered; a series of steps, with associated nameplate capacity and purchase prices that adjust from step to step; and automatic opening of the next step as soon as the nameplate capacity and available purchase prices for an open step are fully committed or reserved. Only projects energized on or after June 1, 2017 shall be eligible for the Adjustable Block program. For each block group the Agency shall determine the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, provided that the purchase price provided and the total amount of generation in all blocks for all block groups shall be sufficient to meet the goals in this subsection (c). The Agency may periodically review its prior decisions establishing the number of blocks, the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values, including but not limited to redistributing these amounts and the available funds as necessary and appropriate, subject to Commission approval as part of the periodic plan revision process described in Section 16-111.5 of the Public Utilities Act. The Agency may define different block sizes, purchase prices, or other distinct terms and conditions for projects located in different utility service territories if the Agency deems it necessary to meet the goals in this subsection (c)<u>; however, if, for any block to be procured on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, the quantity of renewable energy credits sought by eligible projects exceeds the quantity of renewable energy credits defined by the Agency for the block, the Agency</u>

shall lower the price applicable to the block and require eligible projects to affirm the commitment to the quantity of renewable energy credits sought. The Agency shall employ a stepped process of lowering the price applicable to the block so as to identify a price at which the quantity of renewable energy credits sought by eligible projects balances with the renewable energy credits sought by the Agency for the block.

The competitive procurement process used for the procurement of new photovoltaic community renewable generation projects on behalf of electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall define the quantity of renewable energy credits to be procured and allow bidders to submit price offers to the Agency. The Agency shall conduct the competitive procurement process in a manner that results in the lowest cost for the renewable energy credits procured.

The Adjustable Block program and competitive procurement process shall include at least the following block groups in at least the following amounts, which may be adjusted upon review by the Agency and approval by the Commission as described in this subparagraph (K):

(i) At least 25% from distributed renewable energy generation devices with a nameplate capacity of no more than 10 kilowatts.

(ii) At least 25% from distributed renewable energy generation devices with a nameplate capacity of more than 10 kilowatts and no more than 2,000 kilowatts. The Agency may create sub-categories within this category to account for the differences between projects for small commercial customers, large commercial customers, and public or non-profit customers.

(iii) At least 25% from photovoltaic community renewable generation projects.

(iv) The remaining 25% shall be allocated as specified by the Agency in the long-term renewable resources procurement plan.

The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation projects in diverse locations and are not concentrated in a few geographic areas.

(L) The procurement of photovoltaic renewable energy credits under items (i) through (iv) of subparagraph (K) of this paragraph (1) shall be subject to the following contract and payment terms:

(i) The Agency shall procure contracts of at least 15 years in length.

(ii) For those renewable energy credits that qualify and are procured under item (i) of subparagraph (K) of this paragraph (1), the renewable energy credit purchase price shall be paid in full by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized. The electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation.

(iii) For those renewable energy credits that qualify and are procured under item (ii) and (iii) of subparagraph (K) of this paragraph (1) and any additional categories of distributed generation included in the long-term renewable resources procurement plan and approved by the Commission, 20 percent of the renewable energy credit purchase price shall be paid by the contracting utilities at the time that the facility producing the renewable energy credits is interconnected at the distribution system level of the utility and energized. The remaining portion shall be paid ratably over the subsequent 4-year period. The electric utility shall receive and retire all renewable energy credits generated by the project for the first 15 years of operation.

(iv) Each contract shall include provisions to ensure the delivery of the renewable energy credits for the full term of the contract.

(v) The utility shall be the counterparty to the contracts executed under this subparagraph (L) that are approved by the Commission under the process described in Section 16-111.5 of the Public Utilities Act. No contract shall be executed for an amount that is less than one renewable energy credit per year.

(vi) If, at any time, approved applications for the Adjustable Block program exceed funds collected by the electric utility or would cause the Agency to exceed the limitation described in subparagraph (E) of this paragraph (1) on the amount of renewable energy resources that may be procured, then the Agency shall consider future uncommitted funds to be reserved for these contracts on a first-come, first-served basis, with the delivery of renewable energy credits required beginning at the time that the reserved funds become available.

(vii) Nothing in this Section shall require the utility to advance any payment or pay any amounts that exceed the actual amount of revenues collected by the utility under paragraph (6) of this subsection (c) and subsection (k) of Section 16-108 of the Public Utilities Act, and contracts executed under this Section shall expressly incorporate this limitation.

(M) The Agency shall be authorized to retain one or more experts or expert consulting firms to develop, administer, implement, operate, and evaluate the Adjustable Block program described in subparagraph (K) of this paragraph (1), and the Agency shall retain the consultant or consultants in the same manner, to the extent practicable, as the Agency retains others to administer provisions of this Act, including, but not limited to, the procurement administrator. The selection of experts and expert consulting firms and the procurement process described in this subparagraph (M) are exempt from the requirements of Section 20-10 of the Illinois Procurement Code, under Section 20-10 of that Code. The Agency shall strive to minimize administrative expenses in the implementation of the Adjustable Block program.

The Agency and its consultant or consultants shall monitor block activity, share program activity with stakeholders and conduct regularly scheduled meetings to discuss program activity and market conditions. If necessary, the Agency may make prospective administrative adjustments to the Adjustable Block program design, such as redistributing available funds or making adjustments to purchase prices as necessary to achieve the goals of this subsection (c). Program modifications to any price, capacity block, or other program element that do not deviate from the Commission's approved value by more than 25% shall take effect immediately and are not subject to

Commission review and approval. Program modifications to any price, capacity block, or other program element that deviate more than 25% from the Commission's approved value must be approved by the Commission as a long-term plan amendment under Section 16-111.5 of the Public Utilities Act. The Agency shall consider stakeholder feedback when making adjustments to the Adjustable Block design and shall notify stakeholders in advance of any planned changes.

(N) The long-term renewable resources procurement plan required by this subsection (c) shall include a community renewable generation program. The Agency shall establish the terms, conditions, and program requirements for community renewable generation projects with a goal to expand renewable energy generating facility access to a broader group of energy consumers, to ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties. Any plan approved by the Commission shall allow subscriptions to community renewable generation projects to be portable and transferable. For purposes of this subparagraph (N), "portable" means that subscriptions may be retained by the subscriber even if the subscriber relocates or changes its address within the same utility service territory; and "transferable" means that a subscriber may assign or sell subscriptions to another person within the same utility service territory.

Electric utilities shall provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber as specified in Section 16-107.5 of the Public Utilities Act.

The Agency shall purchase renewable energy credits from subscribed shares of photovoltaic community renewable generation projects through the Adjustable Block program and the competitive procurement process described in subparagraph (K) of this paragraph (1) or through the Illinois Solar for All Program described in Section 1-56 of this Act. The electric utility shall purchase any unsubscribed energy from community renewable generation projects that are Qualifying Facilities ("QF") under the electric utility's tariff for purchasing the output from QFs under Public Utilities Regulatory Policies Act of 1978.

The owners of and any subscribers to a community renewable generation project shall not be considered public utilities or alternative retail electricity suppliers under the Public Utilities Act solely as a result of their interest in or subscription to a community renewable generation project and shall not be required to become an alternative retail electric supplier by participating in a community renewable generation project with a public utility.

(O) For the delivery year beginning June 1, 2018, the long-term renewable resources procurement plan required by this subsection (c) shall provide for the Agency to procure contracts to continue offering the Illinois Solar for All Program described in subsection (b) of Section 1-56 of this Act, and the contracts approved by the Commission shall be executed by the utilities that are subject to this subsection (c). The long-term renewable resources procurement plan shall allocate 5% of the funds available under the plan for the applicable delivery year, or $10,000,000 per delivery year, whichever is greater, to fund the programs, and the plan shall determine the amount of funding to be apportioned to the programs identified in subsection (b) of Section 1-56 of this Act; provided that for the delivery years beginning June 1, 2017, June 1, 2021, and June 1, 2025, the long-term renewable resources procurement plan shall allocate 10% of the funds available under the plan for the applicable delivery year, or $20,000,000 per delivery year, whichever is greater, and $10,000,000 of such funds in such year shall be used by an electric utility that serves more than 3,000,000 retail customers in the State to implement a Commission-approved plan under Section 16-108.12 of the Public Utilities Act. In making the determinations required under this subparagraph (O), the Commission shall consider the experience and performance under the programs and any evaluation reports. The Commission shall also provide for an independent evaluation of those programs on a periodic basis that are funded under this subparagraph (O).

(2) (Blank).

(3) (Blank).

(4) The electric utility shall retire all renewable energy credits used to comply with the standard.

(5) Beginning with the 2010 delivery year and ending June 1, 2017, an electric utility subject to this subsection (c) shall apply the lesser of the maximum alternative compliance payment rate or the most recent estimated alternative compliance payment rate for its service territory for the corresponding compliance period, established pursuant to subsection (d) of Section 16-115D of the Public Utilities Act to its retail customers that take service pursuant to the electric utility's hourly pricing tariff or tariffs. The electric utility shall retain all amounts collected as a result of the application of the alternative compliance payment rate or rates to such customers, and, beginning in 2011, the utility shall include in the information provided under item (1) of subsection (d) of Section 16-111.5 of the Public Utilities Act the amounts collected under the alternative compliance payment rate or rates for the prior year ending May 31. Notwithstanding any limitation on the procurement of renewable energy resources imposed by item (2) of this

subsection (c), the Agency shall increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31.

(6) The electric utility shall be entitled to recover all of its costs associated with the procurement of renewable energy credits under plans approved under this Section and Section 16-111.5 of the Public Utilities Act. These costs shall include associated reasonable expenses for implementing the procurement programs, including, but not limited to, the costs of administering and evaluating the Adjustable Block program, through an automatic adjustment clause tariff in accordance with subsection (k) of Section 16-108 of the Public Utilities Act.

(7) Renewable energy credits procured from new photovoltaic projects or new distributed renewable energy generation devices under this Section after June 1, 2017 (the effective date of Public Act 99-906) must be procured from devices installed by a qualified person in compliance with the requirements of Section 16-128A of the Public Utilities Act and any rules or regulations adopted thereunder.

In meeting the renewable energy requirements of this subsection (c), to the extent feasible and consistent with

State and federal law, the renewable energy credit procurements, Adjustable Block solar program, and community renewable generation program shall provide employment opportunities for all segments of the population and workforce, including minority-owned and female-owned business enterprises, and shall not, consistent with State and federal law, discriminate based on race or socioeconomic status.

(d) Clean coal portfolio standard.

(1) The procurement plans shall include electricity generated using clean coal. Each utility shall enter into one or more sourcing agreements with the initial clean coal facility, as provided in paragraph (3) of this subsection (d), covering electricity generated by the initial clean coal facility representing at least 5% of each utility's total supply to serve the load of eligible retail customers in 2015 and each year thereafter, as described in paragraph (3) of this subsection (d), subject to the limits specified in paragraph (2) of this subsection (d). It is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities. For purposes of this subsection (d), "cost-effective" means that the expenditures pursuant to such sourcing agreements do not cause the limit stated in paragraph (2) of this subsection (d) to be exceeded and do not exceed cost-based benchmarks, which shall be developed

to assess all expenditures pursuant to such sourcing agreements covering electricity generated by clean coal facilities, other than the initial clean coal facility, by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval.

A utility party to a sourcing agreement shall immediately retire any emission credits that it receives in connection with the electricity covered by such agreement.

Utilities shall maintain adequate records documenting the purchases under the sourcing agreement to comply with this subsection (d) and shall file an accounting with the load forecast that must be filed with the Agency by July 15 of each year, in accordance with subsection (d) of Section 16-111.5 of the Public Utilities Act.

A utility shall be deemed to have complied with the clean coal portfolio standard specified in this subsection (d) if the utility enters into a sourcing agreement as required by this subsection (d).

(2) For purposes of this subsection (d), the required execution of sourcing agreements with the initial clean coal facility for a particular year shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending

immediately prior to the agreement's execution. For purposes of this subsection (d), the amount paid per kilowatthour means the total amount paid for electric service expressed on a per kilowatthour basis. For purposes of this subsection (d), the total amount paid for electric service includes without limitation amounts paid for supply, transmission, distribution, surcharges and add-on taxes.

Notwithstanding the requirements of this subsection (d), the total amount paid under sourcing agreements with clean coal facilities pursuant to the procurement plan for any given year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to:

(A) in 2010, no more than 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009;

(B) in 2011, the greater of an additional 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2010 or 1% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009;

(C) in 2012, the greater of an additional 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2011 or 1.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009;

(D) in 2013, the greater of an additional 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2012 or 2% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009; and

(E) thereafter, the total amount paid under sourcing agreements with clean coal facilities pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of (i) 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009 or (ii) the incremental amount per kilowatthour paid for these resources in 2013. These requirements may be altered only as provided by statute.

No later than June 30, 2015, the Commission shall review the limitation on the total amount paid under sourcing agreements, if any, with clean coal facilities pursuant to this subsection (d) and report to the General Assembly its findings as to whether that limitation unduly constrains the amount of electricity generated by cost-effective clean coal facilities that is covered by sourcing agreements.

(3) Initial clean coal facility. In order to promote development of clean coal facilities in Illinois, each electric utility subject to this Section shall execute a sourcing agreement to source electricity from a proposed clean coal facility in Illinois (the "initial clean coal facility") that will have a nameplate capacity of at least 500 MW when commercial operation commences, that has a final Clean Air Act permit on June 1, 2009 (the effective date of Public Act 95-1027), and that will meet the definition of clean coal facility in Section 1-10 of this Act when commercial operation commences. The sourcing agreements with this initial clean coal facility shall be subject to both approval of the initial clean coal facility by the General Assembly and satisfaction of the requirements of paragraph (4) of this subsection (d) and shall be executed within 90 days after any such approval by the General Assembly. The Agency and the Commission shall have authority to inspect all books and records associated with the initial clean coal facility during the term of such a sourcing agreement. A utility's sourcing agreement for electricity produced by the initial clean coal facility shall include:

(A) a formula contractual price (the "contract price") approved pursuant to paragraph (4) of this subsection (d), which shall:

(i) be determined using a cost of service methodology employing either a level or deferred capital recovery component, based on a capital structure consisting of 45% equity and 55% debt, and a return on equity as may be approved by the Federal Energy Regulatory Commission, which in any case may not exceed the lower of 11.5% or the rate of return approved by the General Assembly pursuant to paragraph (4) of this subsection (d); and

(ii) provide that all miscellaneous net revenue, including but not limited to net revenue from the sale of emission allowances, if any, substitute natural gas, if any, grants or other support provided by the State of Illinois or the United States Government, firm transmission rights, if any, by-products produced by the facility, energy or capacity derived from the facility and not covered by a sourcing agreement pursuant to paragraph (3) of this subsection (d) or item (5) of subsection (d) of Section 16-115 of the Public Utilities Act, whether generated from the synthesis gas derived from coal, from SNG, or from natural gas, shall be credited against the revenue requirement for this initial clean coal facility;

(B) power purchase provisions, which shall:

(i) provide that the utility party to such sourcing agreement shall pay the contract price for electricity delivered under such sourcing agreement;

(ii) require delivery of electricity to the regional transmission organization market of the utility that is party to such sourcing agreement;

(iii) require the utility party to such sourcing agreement to buy from the initial clean coal facility in each hour an amount of energy equal to all clean coal energy made available from the initial clean coal facility during such hour times a fraction, the numerator of which is such utility's retail market sales of electricity (expressed in kilowatthours sold) in the State during the prior calendar month and the denominator of which is the total retail market sales of electricity (expressed in kilowatthours sold) in the State by utilities during such prior month and the sales of electricity (expressed in kilowatthours sold) in the State by alternative retail electric suppliers during such prior month that are subject to the requirements of this subsection (d) and paragraph (5) of subsection (d) of Section 16-115 of the Public Utilities Act, provided that the amount purchased by the utility in any year will be limited by paragraph (2) of this subsection (d); and

(iv) be considered pre-existing contracts in such utility's procurement plans for eligible retail customers;

(C) contract for differences provisions, which shall:

(i) require the utility party to such sourcing agreement to contract with the initial clean coal facility in each hour with respect to an amount of energy equal to all clean coal energy made available from the initial clean coal facility during such hour times a fraction, the numerator of which is such utility's retail market sales of electricity (expressed in kilowatthours sold) in the utility's service territory in the State during the prior calendar month and the denominator of which is the total retail market sales of electricity (expressed in kilowatthours sold) in the State by utilities during such prior month and the sales of electricity (expressed in kilowatthours sold) in the State by alternative retail electric suppliers during such prior month that are subject to the requirements of this subsection (d) and paragraph (5) of subsection (d) of Section 16-115 of the Public Utilities Act, provided that the amount paid by the utility in any year will be limited by paragraph (2) of this subsection (d);

(ii) provide that the utility's payment obligation in respect of the quantity of electricity determined pursuant to the preceding clause (i) shall be limited to an amount equal to (1) the difference between the contract price determined pursuant to subparagraph (A) of paragraph (3) of this subsection (d) and the day-ahead price for electricity delivered to the regional transmission organization market of the utility that is party to such sourcing agreement (or any successor delivery point at which such utility's supply obligations are financially settled on an hourly basis) (the "reference price") on the day preceding the day on which the electricity is delivered to the initial clean coal facility busbar, multiplied by (2) the quantity of electricity determined pursuant to the preceding clause (i); and

(iii) not require the utility to take physical delivery of the electricity produced by the facility;

(D) general provisions, which shall:

(i) specify a term of no more than 30 years, commencing on the commercial operation date of the facility;

(ii) provide that utilities shall maintain adequate records documenting purchases under the sourcing agreements entered into to comply with this subsection (d) and shall file an accounting with the load forecast that must be filed with the Agency by July 15 of each year, in accordance with subsection (d) of Section 16-111.5 of the Public Utilities Act;

(iii) provide that all costs associated with the initial clean coal facility will be periodically reported to the Federal Energy Regulatory Commission and to purchasers in accordance with applicable laws governing cost-based wholesale power contracts;

(iv) permit the Illinois Power Agency to assume ownership of the initial clean coal facility, without monetary consideration and otherwise on reasonable terms acceptable to the Agency, if the Agency so requests no less than 3 years prior to the end of the stated contract term;

(v) require the owner of the initial clean coal facility to provide documentation to the

Commission each year, starting in the facility's first year of commercial operation, accurately reporting the quantity of carbon emissions from the facility that have been captured and sequestered and report any quantities of carbon released from the site or sites at which carbon emissions were sequestered in prior years, based on continuous monitoring of such sites. If, in any year after the first year of commercial operation, the owner of the facility fails to demonstrate that the initial clean coal facility captured and sequestered at least 50% of the total carbon emissions that the facility would otherwise emit or that sequestration of emissions from prior years has failed, resulting in the release of carbon dioxide into the atmosphere, the owner of the facility must offset excess emissions. Any such carbon offsets must be permanent, additional, verifiable, real, located within the State of Illinois, and legally and practicably enforceable. The cost of such offsets for the facility that are not recoverable shall not exceed $15 million in any given year. No costs of any such purchases of carbon offsets may be recovered from a utility or its customers. All carbon offsets purchased for this purpose and any carbon emission credits associated with sequestration of carbon from the facility must be permanently retired. The initial clean coal facility shall not forfeit its designation as a clean coal facility if the facility fails to fully comply with the applicable carbon sequestration requirements in any given year, provided the requisite offsets are purchased. However, the Attorney General, on behalf of the People of the State of Illinois, may specifically enforce the facility's sequestration requirement and the other terms of this contract provision. Compliance with the sequestration requirements and offset purchase requirements specified in paragraph (3) of this subsection (d) shall be reviewed annually by an independent expert retained by the owner of the initial clean coal facility, with the advance written approval of the Attorney General. The Commission may, in the course of the review specified in item (vii), reduce the allowable return on equity for the facility if the facility willfully fails to comply with the carbon capture and sequestration requirements set forth in this item (v);

(vi) include limits on, and accordingly provide for modification of, the amount the utility is required to source under the sourcing agreement consistent with paragraph (2) of this subsection (d);

(vii) require Commission review: (1) to determine the justness, reasonableness, and prudence of the inputs to the formula referenced in subparagraphs (A)(i) through (A)(iii) of paragraph (3) of this subsection (d), prior to an adjustment in those inputs including, without limitation, the capital structure and return on equity, fuel costs, and other operations and maintenance costs and (2) to approve the costs to be passed through to customers under the sourcing agreement by which the utility satisfies its statutory obligations. Commission review shall occur no less than every 3 years, regardless of whether any adjustments have been proposed, and shall be completed within 9 months;

(viii) limit the utility's obligation to such amount as the utility is allowed to recover through tariffs filed with the Commission, provided that neither the clean coal facility nor the utility waives any right to assert federal pre-emption or any other argument in response to a purported disallowance of recovery costs;

(ix) limit the utility's or alternative retail electric supplier's obligation to incur any liability until such time as the facility is in commercial operation and generating power and energy and such power and energy is being delivered to the facility busbar;

(x) provide that the owner or owners of the initial clean coal facility, which is the counterparty to such sourcing agreement, shall have the right from time to time to elect whether the obligations of the utility party thereto shall be governed by the power purchase provisions or the contract for differences provisions;

(xi) append documentation showing that the formula rate and contract, insofar as they relate to the power purchase provisions, have been approved by the Federal Energy Regulatory Commission pursuant to Section 205 of the Federal Power Act;

(xii) provide that any changes to the terms of the contract, insofar as such changes relate to the power purchase provisions, are subject to review under the public interest standard applied by the Federal Energy Regulatory Commission pursuant to Sections 205 and 206 of the Federal Power Act; and

(xiii) conform with customary lender requirements in power purchase agreements used as the basis for financing non-utility generators.

(4) Effective date of sourcing agreements with the initial clean coal facility. Any proposed sourcing agreement with the initial clean coal facility shall not become effective unless the following reports are prepared and submitted and authorizations and approvals obtained:

(i) Facility cost report. The owner of the initial clean coal facility shall submit to the Commission, the Agency, and the General Assembly a front-end engineering and design study, a facility cost report, method of financing (including but not limited to structure and associated costs), and an operating and maintenance cost quote for the facility (collectively "facility cost report"), which shall be prepared in accordance with the requirements of this paragraph (4) of subsection (d) of this Section, and shall provide the Commission and the Agency access to the work papers, relied upon documents, and any other backup documentation related to the facility cost report.

(ii) Commission report. Within 6 months following receipt of the facility cost report, the Commission, in consultation with the Agency, shall submit a report to the General Assembly setting forth its analysis of the facility cost report. Such report shall include, but not be limited to, a comparison of the costs associated with electricity generated by the initial clean coal facility to the costs associated with electricity generated by other types of generation facilities, an analysis of the rate impacts on residential and small business customers over the life of the sourcing agreements, and an analysis of the likelihood that the initial clean coal facility will commence commercial operation by and be delivering power to the facility's busbar by 2016. To assist in the preparation of its report, the Commission, in consultation with the Agency, may hire one or more experts or consultants, the costs of which shall be paid for by the owner of the initial clean coal facility. The Commission and Agency may begin the process of selecting such experts or consultants prior to receipt of the facility cost report.

(iii) General Assembly approval. The proposed sourcing agreements shall not take effect unless, based on the facility cost report and the Commission's report, the General Assembly enacts authorizing legislation approving (A) the projected price, stated in cents per kilowatthour, to be charged for electricity generated by the initial clean coal facility, (B) the projected impact on residential and small business customers' bills over the life of the sourcing agreements, and (C) the maximum allowable return on equity for the project; and

(iv) Commission review. If the General Assembly enacts authorizing legislation pursuant to subparagraph (iii) approving a sourcing agreement, the Commission shall, within 90 days of such enactment, complete a review of such sourcing agreement. During such time period, the Commission shall implement any directive of the General Assembly, resolve any disputes between the parties to the sourcing agreement concerning the terms of such agreement, approve the form of such agreement, and issue an order finding that the sourcing agreement is prudent and reasonable.

The facility cost report shall be prepared as follows:

(A) The facility cost report shall be prepared by duly licensed engineering and construction firms detailing the estimated capital costs payable to one or more contractors or suppliers for the engineering, procurement and construction of the components comprising the initial clean coal facility and the estimated costs of operation and maintenance of the facility. The facility cost report shall include:

(i) an estimate of the capital cost of the core plant based on one or more front end engineering and design studies for the gasification island and related facilities. The core plant shall include all civil, structural, mechanical, electrical, control, and safety systems.

(ii) an estimate of the capital cost of the balance of the plant, including any capital costs associated with sequestration of carbon dioxide emissions and all interconnects and interfaces required to operate the facility, such as transmission of electricity, construction or backfeed power supply, pipelines to transport substitute natural gas or carbon dioxide, potable water supply, natural gas supply, water supply, water discharge, landfill, access roads, and coal delivery.

The quoted construction costs shall be expressed in nominal dollars as of the date that the quote is prepared and shall include capitalized financing costs during construction, taxes, insurance, and other owner's costs, and an assumed escalation in materials and labor beyond the date as of which the construction cost quote is expressed.

(B) The front end engineering and design study for the gasification island and the cost study for the balance of plant shall include sufficient design work to permit quantification of major categories of materials, commodities and labor hours, and receipt of quotes from vendors of major equipment required to construct and operate the clean coal facility.

(C) The facility cost report shall also include an operating and maintenance cost quote that will provide the estimated cost of delivered fuel, personnel, maintenance contracts, chemicals, catalysts, consumables, spares, and other fixed and variable operations and maintenance costs. The delivered fuel cost estimate will be provided by a recognized third party expert or experts in the fuel and transportation industries. The balance of the operating and maintenance cost quote, excluding delivered fuel costs, will be developed based on the inputs provided by duly licensed engineering and construction firms performing the construction cost quote, potential vendors under long-term service agreements and plant operating agreements, or recognized third party plant operator or operators.

The operating and maintenance cost quote (including the cost of the front end engineering and design study) shall be expressed in nominal dollars as of the date that the quote is prepared and shall include taxes, insurance, and other owner's costs, and an assumed escalation in materials and labor beyond the date as of which the operating and maintenance cost quote is expressed.

(D) The facility cost report shall also include an analysis of the initial clean coal facility's ability to deliver power and energy into the applicable regional transmission organization markets and an analysis of the expected capacity factor for the initial clean coal facility.

(E) Amounts paid to third parties unrelated to the owner or owners of the initial clean coal facility to prepare the core plant construction cost quote, including the front end engineering and design study, and the operating and maintenance cost quote will be reimbursed through Coal Development Bonds.

(5) Re-powering and retrofitting coal-fired power plants previously owned by Illinois utilities to qualify as clean coal facilities. During the 2009 procurement planning process and thereafter, the Agency and the Commission shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities, as defined by Section 1-10 of this Act. Pursuant to such procurement planning process, the owners of such facilities may propose to the Agency sourcing agreements with utilities and alternative retail electric suppliers required to comply with subsection (d) of this Section and item (5) of subsection (d) of Section 16-115 of the Public Utilities Act, covering electricity generated by such facilities. In the case of sourcing agreements that are power purchase agreements, the contract price for electricity sales shall be established on a cost of service basis. In the case of

sourcing agreements that are contracts for differences, the contract price from which the reference price is subtracted shall be established on a cost of service basis. The Agency and the Commission may approve any such utility sourcing agreements that do not exceed cost-based benchmarks developed by the procurement administrator, in consultation with the Commission staff, Agency staff and the procurement monitor, subject to Commission review and approval. The Commission shall have authority to inspect all books and records associated with these clean coal facilities during the term of any such contract.

(6) Costs incurred under this subsection (d) or pursuant to a contract entered into under this subsection (d) shall be deemed prudently incurred and reasonable in amount and the electric utility shall be entitled to full cost recovery pursuant to the tariffs filed with the Commission.

(d-5) Zero emission standard.

(1) Beginning with the delivery year commencing on June 1, 2017, the Agency shall, for electric utilities that serve at least 100,000 retail customers in this State, procure contracts with zero emission facilities that are reasonably capable of generating cost-effective zero emission credits in an amount approximately equal to 16% of the actual amount of electricity delivered by each electric utility to retail customers in the State during calendar

year 2014. For an electric utility serving fewer than 100,000 retail customers in this State that requested, under Section 16-111.5 of the Public Utilities Act, that the Agency procure power and energy for all or a portion of the utility's Illinois load for the delivery year commencing June 1, 2016, the Agency shall procure contracts with zero emission facilities that are reasonably capable of generating cost-effective zero emission credits in an amount approximately equal to 16% of the portion of power and energy to be procured by the Agency for the utility. The duration of the contracts procured under this subsection (d-5) shall be for a term of 10 years ending May 31, 2027. The quantity of zero emission credits to be procured under the contracts shall be all of the zero emission credits generated by the zero emission facility in each delivery year; however, if the zero emission facility is owned by more than one entity, then the quantity of zero emission credits to be procured under the contracts shall be the amount of zero emission credits that are generated from the portion of the zero emission facility that is owned by the winning supplier.

The 16% value identified in this paragraph (1) is the average of the percentage targets in subparagraph (B) of paragraph (1) of subsection (c) of this Section for the 5 delivery years beginning June 1, 2017.

The procurement process shall be subject to the following provisions:

(A) Those zero emission facilities that intend to participate in the procurement shall submit to the Agency the following eligibility information for each zero emission facility on or before the date established by the Agency:

(i) the in-service date and remaining useful life of the zero emission facility;

(ii) the amount of power generated annually for each of the years 2005 through 2015, and the projected zero emission credits to be generated over the remaining useful life of the zero emission facility, which shall be used to determine the capability of each facility;

(iii) the annual zero emission facility cost projections, expressed on a per megawatthour basis, over the next 6 delivery years, which shall include the following: operation and maintenance expenses; fully allocated overhead costs, which shall be allocated using the methodology developed by the Institute for Nuclear Power Operations; fuel expenditures; non-fuel capital expenditures; spent fuel expenditures; a return on working capital; the cost of operational and market risks that could be avoided by ceasing operation; and any other costs necessary for continued operations, provided that "necessary" means, for purposes of this item (iii), that the costs could reasonably be avoided only by ceasing operations of the zero emission facility; and

(iv) a commitment to continue operating, for the duration of the contract or contracts executed under the procurement held under this subsection (d-5), the zero emission facility that produces the zero emission credits to be procured in the procurement.

The information described in item (iii) of this subparagraph (A) may be submitted on a confidential basis and shall be treated and maintained by the Agency, the procurement administrator, and the Commission as confidential and proprietary and exempt from disclosure under subparagraphs (a) and (g) of paragraph (1) of Section 7 of the Freedom of Information Act. The Office of Attorney General shall have access to, and maintain the confidentiality of, such information pursuant to Section 6.5 of the Attorney General Act.

(B) The price for each zero emission credit procured under this subsection (d-5) for each delivery year shall be in an amount that equals the Social Cost of Carbon, expressed on a price per megawatthour basis. However, to ensure that the procurement remains affordable to retail customers in this State if electricity prices increase, the price in an applicable delivery year shall be reduced below the Social Cost of Carbon by the amount ("Price Adjustment") by which the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016. If the Price Adjustment is greater than or equal to the Social Cost of Carbon in an applicable delivery year, then no payments shall be due in that delivery year. The components of this calculation are defined as follows:

(i) Social Cost of Carbon: The Social Cost of Carbon is $16.50 per megawatthour, which is based on the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update using a 3% discount rate, adjusted for inflation for each year of the program. Beginning with the delivery year commencing June 1, 2023, the price per megawatthour shall increase by $1 per megawatthour, and continue to increase by an additional $1 per megawatthour each delivery year thereafter.

(ii) Baseline market price index: The baseline market price index for the consecutive 12-month period ending May 31, 2016 is $31.40 per megawatthour, which is based on the sum of (aa) the average day-ahead energy price across all hours of such 12-month period at the PJM Interconnection LLC Northern Illinois Hub, (bb) 50% multiplied by the Base Residual Auction, or its successor, capacity price for the rest of the RTO zone group determined by PJM Interconnection LLC, divided by 24 hours per day, and (cc) 50% multiplied by the Planning Resource Auction, or its successor, capacity price for Zone 4 determined by the Midcontinent Independent System Operator, Inc., divided by 24 hours per day.

(iii) Market price index: The market price index for a delivery year shall be the sum of projected energy prices and projected capacity prices determined as follows:

(aa) Projected energy prices: the projected energy prices for the applicable delivery year shall be calculated once for the year using the forward market price for the PJM Interconnection, LLC Northern Illinois Hub. The forward market price shall be calculated as follows: the energy forward prices for each month of the applicable delivery year averaged for each trade date during the calendar year immediately preceding that delivery year to produce a single energy forward price for the delivery year. The forward market price calculation shall use data published by the Intercontinental Exchange, or its successor.

(bb) Projected capacity prices:

(I) For the delivery years commencing June 1, 2017, June 1, 2018, and June 1, 2019, the projected capacity price shall be equal to the sum of (1) 50% multiplied by the Base Residual Auction, or its successor, price for the rest of the RTO zone group as determined by PJM Interconnection LLC, divided by 24 hours per day and, (2) 50% multiplied by the resource auction price determined in the resource auction administered by the Midcontinent Independent System Operator, Inc., in which the largest percentage of load cleared for Local Resource Zone 4, divided by 24 hours per day, and where such price is determined by the Midcontinent Independent System Operator, Inc.

(II) For the delivery year commencing June 1, 2020, and each year thereafter, the projected capacity price shall be equal to the sum of (1) 50% multiplied by the Base

Residual Auction, or its successor, price for the ComEd zone as determined by PJM Interconnection LLC, divided by 24 hours per day, and (2) 50% multiplied by the resource auction price determined in the resource auction administered by the Midcontinent Independent System Operator, Inc., in which the largest percentage of load cleared for Local Resource Zone 4, divided by 24 hours per day, and where such price is determined by the Midcontinent Independent System Operator, Inc.

For purposes of this subsection (d-5):

"Rest of the RTO" and "ComEd Zone" shall have the meaning ascribed to them by PJM Interconnection, LLC.

"RTO" means regional transmission organization.

(C) No later than 45 days after June 1, 2017 (the effective date of Public Act 99-906), the Agency shall publish its proposed zero emission standard procurement plan. The plan shall be consistent with the provisions of this paragraph (1) and shall provide that winning bids shall be selected based on public interest criteria that include, but are not limited to, minimizing carbon dioxide emissions that result from electricity consumed in Illinois and minimizing sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect the citizens of this State. In particular, the selection of winning bids shall take into account the incremental environmental benefits resulting from the procurement, such as any existing environmental benefits that are preserved by the procurements held under Public Act 99-906 and would cease to exist if the procurements were not held, including the preservation of zero emission facilities. The plan shall also describe in detail how each public interest factor shall be considered and weighted in the bid selection process to ensure that the public interest criteria are applied to the procurement and given full effect.

For purposes of developing the plan, the Agency shall consider any reports issued by a State agency, board, or commission under House Resolution 1146 of the 98th General Assembly and paragraph (4) of subsection (d) of this Section, as well as publicly available analyses and studies performed by or for regional transmission organizations that serve the State and their independent market monitors.

Upon publishing of the zero emission standard procurement plan, copies of the plan shall be posted and made publicly available on the Agency's website.

All interested parties shall have 10 days following the date of posting to provide comment to the Agency on the plan. All comments shall be posted to the Agency's website. Following the end of the comment period, but no more than 60 days later than June 1, 2017 (the effective date of Public Act 99-906), the Agency shall revise the plan as necessary based on the comments received and file its zero emission standard procurement plan with the Commission.

If the Commission determines that the plan will result in the procurement of cost-effective zero emission credits, then the Commission shall, after notice and hearing, but no later than 45 days after the Agency filed the plan, approve the plan or approve with modification. For purposes of this subsection (d-5), "cost effective" means the projected costs of procuring zero emission credits from zero emission facilities do not cause the limit stated in paragraph (2) of this subsection to be exceeded.

(C-5) As part of the Commission's review and acceptance or rejection of the procurement results, the Commission shall, in its public notice of successful bidders:

(i) identify how the winning bids satisfy the public interest criteria described in subparagraph (C) of this paragraph (1) of minimizing carbon dioxide emissions that result from electricity consumed in Illinois and minimizing sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect the citizens of this State;

(ii) specifically address how the selection of winning bids takes into account the incremental environmental benefits resulting from the procurement, including any existing environmental benefits that are preserved by the procurements held under Public Act 99-906 and would have ceased to exist if the procurements had not been held, such as the preservation of zero emission facilities;

(iii) quantify the environmental benefit of preserving the resources identified in item (ii) of this subparagraph (C-5), including the following:

(aa) the value of avoided greenhouse gas emissions measured as the product of the zero emission facilities' output over the contract term multiplied by the U.S. Environmental Protection Agency eGrid subregion carbon dioxide emission rate and the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update using a 3%

discount rate, adjusted for inflation for each delivery year; and

(bb) the costs of replacement with other zero carbon dioxide resources, including wind and photovoltaic, based upon the simple average of the following:

(I) the price, or if there is more than one price, the average of the prices, paid for renewable energy credits from new utility-scale wind projects in the procurement events specified in item (i) of subparagraph (G) of paragraph (1) of subsection (c) of this Section; and

(II) the price, or if there is more than one price, the average of the prices, paid for renewable energy credits from new utility-scale solar projects and brownfield site photovoltaic projects in the procurement events specified in item (ii) of subparagraph (G) of paragraph (1) of subsection (c) of this Section and, after January 1, 2015, renewable energy credits from photovoltaic distributed generation projects in procurement events held under subsection (c) of this Section.

Each utility shall enter into binding contractual arrangements with the winning suppliers.

The procurement described in this subsection (d-5), including, but not limited to, the execution of all contracts procured, shall be completed no later than May 10, 2017. Based on the effective date of Public Act 99-906, the Agency and Commission may, as appropriate, modify the various dates and timelines under this subparagraph and subparagraphs (C) and (D) of this paragraph (1). The procurement and plan approval processes required by this subsection (d-5) shall be conducted in conjunction with the procurement and plan approval processes required by subsection (c) of this Section and Section 16-111.5 of the Public Utilities Act, to the extent practicable. Notwithstanding whether a procurement event is conducted under Section 16-111.5 of the Public Utilities Act, the Agency shall immediately initiate a procurement process on June 1, 2017 (the effective date of Public Act 99-906).

(D) Following the procurement event described in this paragraph (1) and consistent with subparagraph (B) of this paragraph (1), the Agency shall calculate the payments to be made under each contract for the next delivery year based on the market price index for that delivery year. The Agency shall publish the payment calculations no later than May 25, 2017 and every May 25 thereafter.

(E) Notwithstanding the requirements of this subsection (d-5), the contracts executed under this subsection (d-5) shall provide that the zero emission facility may, as applicable, suspend or terminate performance under the contracts in the following instances:

(i) A zero emission facility shall be excused from its performance under the contract for any cause beyond the control of the resource, including, but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of commercially reasonable efforts the zero emission facility could not reasonably have been expected to avoid, and which, by the exercise of commercially reasonable efforts, it has been unable to overcome. In such event, the zero emission facility shall be excused from performance for the duration of the event, including, but not limited to, delivery of zero emission credits, and no payment shall be due to the zero emission facility during the duration of the event.

(ii) A zero emission facility shall be permitted to terminate the contract if legislation is enacted into law by the General Assembly that imposes or authorizes a new tax, special assessment, or fee on the generation of electricity, the ownership or leasehold of a generating unit, or the privilege or occupation of such generation, ownership, or leasehold of generation units by a zero emission facility. However, the provisions of this item (ii) do not apply to any generally applicable tax, special assessment or fee, or requirements imposed by federal law.

(iii) A zero emission facility shall be permitted to terminate the contract in the event that the resource requires capital expenditures in excess of $40,000,000 that were neither known nor reasonably foreseeable at the time it executed the contract and that a prudent owner or operator of such resource would not undertake.

(iv) A zero emission facility shall be permitted to terminate the contract in the event the Nuclear Regulatory Commission terminates the resource's license.

(F) If the zero emission facility elects to terminate a contract under subparagraph (E) of this paragraph (1), then the Commission shall reopen the docket in which the Commission approved the zero emission standard procurement plan under subparagraph (C) of this paragraph (1) and, after notice and hearing, enter an order acknowledging the contract termination election if such termination is consistent with the provisions of this subsection (d-5).

(2) For purposes of this subsection (d-5), the amount paid per kilowatthour means the total amount paid for electric service expressed on a per kilowatthour basis. For purposes of this subsection (d-5), the total amount paid for electric service includes, without limitation, amounts paid for supply, transmission, distribution, surcharges, and add-on taxes.

Notwithstanding the requirements of this subsection (d-5), the contracts executed under this subsection (d-5) shall provide that the total of zero emission credits procured under a procurement plan shall be subject to the limitations of this paragraph (2). For each delivery year, the contractual volume receiving payments in such year shall be reduced for all retail customers based on the amount necessary to limit the net increase that delivery year to the costs of those credits included in the amounts paid by eligible retail customers in connection with electric service to no more than 1.65% of the amount paid per kilowatthour by eligible retail customers during the year ending May 31, 2009. The result of this computation shall apply to and reduce the procurement for all retail customers, and all those customers shall pay the same single, uniform cents per kilowatthour charge under subsection (k) of Section 16-108 of the Public Utilities Act. To arrive at a maximum dollar amount of zero emission credits to be paid for the particular delivery year, the resulting per kilowatthour amount shall be applied to the actual amount of kilowatthours of electricity delivered by the electric utility in the delivery year immediately prior to the procurement, to all retail customers in its service territory. Unpaid contractual volume for any delivery year shall be paid in any subsequent delivery year in which such payments can be made without exceeding the amount specified in this paragraph (2). The calculations required by this paragraph (2) shall be made only once for each procurement plan year. Once the determination as to the amount of zero emission credits to be paid is made based on the calculations set forth in this paragraph (2), no subsequent rate impact determinations shall be made and no adjustments to those contract amounts shall be allowed. All costs incurred under those contracts and in implementing this subsection (d-5) shall be recovered by the electric utility as provided in this Section.

No later than June 30, 2019, the Commission shall review the limitation on the amount of zero emission credits procured under this subsection (d-5) and report to the General Assembly its findings as to whether that limitation unduly constrains the procurement of cost-effective zero emission credits.

(3) Six years after the execution of a contract under this subsection (d-5), the Agency shall determine whether the actual zero emission credit payments received by the supplier over the 6-year period exceed the Average ZEC Payment. In addition, at the end of the term of a contract executed under this subsection (d-5), or at the time, if any, a zero emission facility's contract is terminated under subparagraph (E) of paragraph (1) of this subsection (d-5), then the Agency shall determine whether the actual zero emission credit payments received by the supplier over the term of the contract exceed the Average ZEC Payment, after taking into account any amounts previously credited back to the utility under this paragraph (3). If the Agency determines that the actual zero emission credit payments received by the supplier over the relevant period exceed the Average ZEC Payment, then the supplier shall credit the difference back to the utility. The amount of the credit shall be remitted to the applicable electric utility no later than 120 days after the Agency's determination, which

the utility shall reflect as a credit on its retail customer bills as soon as practicable; however, the credit remitted to the utility shall not exceed the total amount of payments received by the facility under its contract.

For purposes of this Section, the Average ZEC Payment shall be calculated by multiplying the quantity of zero emission credits delivered under the contract times the average contract price. The average contract price shall be determined by subtracting the amount calculated under subparagraph (B) of this paragraph (3) from the amount calculated under subparagraph (A) of this paragraph (3), as follows:

(A) The average of the Social Cost of Carbon, as defined in subparagraph (B) of paragraph (1) of this subsection (d-5), during the term of the contract.

(B) The average of the market price indices, as defined in subparagraph (B) of paragraph (1) of this subsection (d-5), during the term of the contract, minus the baseline market price index, as defined in subparagraph (B) of paragraph (1) of this subsection (d-5).

If the subtraction yields a negative number, then the Average ZEC Payment shall be zero.

(4) Cost-effective zero emission credits procured from zero emission facilities shall satisfy the applicable definitions set forth in Section 1-10 of this Act.

(5) The electric utility shall retire all zero emission credits used to comply with the requirements of this subsection (d-5).

(6) Electric utilities shall be entitled to recover all of the costs associated with the procurement of zero emission credits through an automatic adjustment clause tariff in accordance with subsection (k) and (m) of Section 16-108 of the Public Utilities Act, and the contracts executed under this subsection (d-5) shall provide that the utilities' payment obligations under such contracts shall be reduced if an adjustment is required under subsection (m) of Section 16-108 of the Public Utilities Act.

(7) This subsection (d-5) shall become inoperative on January 1, 2028.

(e) The draft procurement plans are subject to public comment, as required by Section 16-111.5 of the Public Utilities Act.

(f) The Agency shall submit the final procurement plan to the Commission. The Agency shall revise a procurement plan if the Commission determines that it does not meet the standards set forth in Section 16-111.5 of the Public Utilities Act.

(g) The Agency shall assess fees to each affected utility to recover the costs incurred in preparation of the annual procurement plan for the utility.

(h) The Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process.

(i) A renewable energy credit, carbon emission credit, or zero emission credit can only be used once to comply with a single portfolio or other standard as set forth in subsection (c), subsection (d), or subsection (d-5) of this Section, respectively. A renewable energy credit, carbon emission credit, or zero emission credit cannot be used to satisfy the requirements of more than one standard. If more than one type of credit is issued for the same megawatt hour of energy, only one credit can be used to satisfy the requirements of a single standard. After such use, the credit must be retired together with any other credits issued for the same megawatt hour of energy.

(Source: P.A. 100-863, eff. 8-14-18; 101-81, eff. 7-12-19; 101-113, eff. 1-1-20.)

Section 10. The Public Utilities Act is amended by changing Sections 8-103B, 16-102, 16-107.6, 16-108.5, and 16-128A and by adding Sections 8-218, 16-108.19 and 16-108.20 as follows:

(220 ILCS 5/8-103B)

Sec. 8-103B. Energy efficiency and demand-response measures.

(a) It is the policy of the State that electric utilities are required to use cost-effective energy efficiency and demand-response measures to reduce <u>the total Btus of</u>

electricity, natural gas, or other fuels needed to meet the end use or uses for all retail customers ~~delivery load~~. Requiring investment in cost-effective energy efficiency and demand-response measures will reduce direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure. It serves the public interest to allow electric utilities to recover costs for reasonably and prudently incurred expenditures for energy efficiency and demand-response measures. As used in this Section, "cost-effective" means that the measures satisfy the total resource cost test. The low-income measures described in subsection (c) of this Section shall not be required to meet the total resource cost test. For purposes of this Section, the terms "energy-efficiency", "demand-response", "electric utility", and "total resource cost test" have the meanings set forth in the Illinois Power Agency Act.

(a-5) This Section applies to electric utilities serving more than 500,000 retail customers in the State for those multi-year plans commencing after December 31, 2017.

(b) For purposes of this Section, electric utilities subject to this Section that serve more than 3,000,000 retail customers in the State shall be deemed to have achieved a cumulative persisting annual savings of 6.6% from energy efficiency measures and programs implemented during the period beginning January 1, 2012 and ending December 31, 2017, which percent is based on the deemed average weather normalized sales of electric power and energy during calendar years 2014, 2015, and 2016 of 88,000,000 MWhs. For the purposes of this subsection (b) and subsection (b-5), the 88,000,000 MWhs of deemed electric power and energy sales shall be reduced by the number of MWhs equal to the sum of the annual consumption of customers that are exempt from subsections (a) through (j) of this Section under subsection (l) of this Section, as averaged across the calendar years 2014, 2015, and 2016. After 2017, the deemed value of cumulative persisting annual savings from energy efficiency measures and programs implemented during the period beginning January 1, 2012 and ending December 31, 2017, shall be reduced each year, as follows, and the applicable value shall be applied to and count toward the utility's achievement of the cumulative persisting annual savings goals set forth in subsection (b-5):

(1) 5.8% deemed cumulative persisting annual savings for the year ending December 31, 2018;

(2) 5.2% deemed cumulative persisting annual savings for the year ending December 31, 2019;

(3) 4.5% deemed cumulative persisting annual savings for the year ending December 31, 2020;

(4) 4.0% deemed cumulative persisting annual savings for the year ending December 31, 2021;

(5) 3.5% deemed cumulative persisting annual savings for the year ending December 31, 2022;

(6) 3.1% deemed cumulative persisting annual savings for the year ending December 31, 2023;

(7) 2.8% deemed cumulative persisting annual savings for the year ending December 31, 2024;

(8) 2.5% deemed cumulative persisting annual savings for the year ending December 31, 2025;

(9) 2.3% deemed cumulative persisting annual savings for the year ending December 31, 2026;

(10) 2.1% deemed cumulative persisting annual savings for the year ending December 31, 2027;

(11) 1.8% deemed cumulative persisting annual savings for the year ending December 31, 2028;

(12) 1.7% deemed cumulative persisting annual savings for the year ending December 31, 2029; and

(13) 1.5% deemed cumulative persisting annual savings for the year ending December 31, 2030.

For purposes of this Section, "cumulative persisting annual savings" means the total electric energy savings in a given year from measures installed in that year or in previous years, but no earlier than January 1, 2012, that are still operational and providing savings in that year because the measures have not yet reached the end of their useful lives.

(b-5) Beginning in 2018, electric utilities subject to this Section that serve more than 3,000,000 retail customers in the State shall achieve the following cumulative persisting annual savings goals, as modified by subsection (f) of this Section and as compared to the deemed baseline of 88,000,000 MWhs of electric power and energy sales set forth in subsection (b), as reduced by the number of MWhs equal to the sum of the annual consumption of customers that are exempt from subsections (a) through (j) of this Section under subsection (l) of this Section as averaged across the calendar years 2014, 2015, and 2016, through the implementation of energy efficiency measures during the applicable year and in prior years, but no earlier than January 1, 2012:

(1) 7.8% cumulative persisting annual savings for the year ending December 31, 2018;

(2) 9.1% cumulative persisting annual savings for the year ending December 31, 2019;

(3) 10.4% cumulative persisting annual savings for the year ending December 31, 2020;

(4) 11.8% cumulative persisting annual savings for the year ending December 31, 2021;

(5) 13.1% cumulative persisting annual savings for the year ending December 31, 2022;

(6) 14.4% cumulative persisting annual savings for the year ending December 31, 2023;

(7) 15.7% cumulative persisting annual savings for the year ending December 31, 2024;

(8) 17% cumulative persisting annual savings for the year ending December 31, 2025;

(9) 17.9% cumulative persisting annual savings for the

year ending December 31, 2026;

(10) 18.8% cumulative persisting annual savings for the year ending December 31, 2027;

(11) 19.7% cumulative persisting annual savings for the year ending December 31, 2028;

(12) 20.6% cumulative persisting annual savings for the year ending December 31, 2029; and

(13) 21.5% cumulative persisting annual savings for the year ending December 31, 2030.

(b-10) For purposes of this Section, electric utilities subject to this Section that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State shall be deemed to have achieved a cumulative persisting annual savings of 6.6% from energy efficiency measures and programs implemented during the period beginning January 1, 2012 and ending December 31, 2017, which is based on the deemed average weather normalized sales of electric power and energy during calendar years 2014, 2015, and 2016 of 36,900,000 MWhs. For the purposes of this subsection (b-10) and subsection (b-15), the 36,900,000 MWhs of deemed electric power and energy sales shall be reduced by the number of MWhs equal to the sum of the annual consumption of customers that are exempt from subsections (a) through (j) of this Section under subsection (l) of this Section, as averaged across the calendar years 2014, 2015, and 2016. After 2017, the deemed value of cumulative persisting annual savings from energy efficiency measures and programs implemented during the period beginning January 1, 2012 and ending December 31, 2017, shall be reduced each year, as follows, and the applicable value shall be applied to and count toward the utility's achievement of the cumulative persisting annual savings goals set forth in subsection (b-15):

(1) 5.8% deemed cumulative persisting annual savings for the year ending December 31, 2018;

(2) 5.2% deemed cumulative persisting annual savings for the year ending December 31, 2019;

(3) 4.5% deemed cumulative persisting annual savings for the year ending December 31, 2020;

(4) 4.0% deemed cumulative persisting annual savings for the year ending December 31, 2021;

(5) 3.5% deemed cumulative persisting annual savings for the year ending December 31, 2022;

(6) 3.1% deemed cumulative persisting annual savings for the year ending December 31, 2023;

(7) 2.8% deemed cumulative persisting annual savings for the year ending December 31, 2024;

(8) 2.5% deemed cumulative persisting annual savings for the year ending December 31, 2025;

(9) 2.3% deemed cumulative persisting annual savings for the year ending December 31, 2026;

(10) 2.1% deemed cumulative persisting annual savings for the year ending December 31, 2027;

(11) 1.8% deemed cumulative persisting annual savings

for the year ending December 31, 2028;

(12) 1.7% deemed cumulative persisting annual savings for the year ending December 31, 2029; and

(13) 1.5% deemed cumulative persisting annual savings for the year ending December 31, 2030.

(b-15) Beginning in 2018, electric utilities subject to this Section that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State shall achieve the following cumulative persisting annual savings goals, as modified by subsection (b-20) and subsection (f) of this Section and as compared to the deemed baseline as reduced by the number of MWhs equal to the sum of the annual consumption of customers that are exempt from subsections (a) through (j) of this Section under subsection (l) of this Section as averaged across the calendar years 2014, 2015, and 2016, through the implementation of energy efficiency measures during the applicable year and in prior years, but no earlier than January 1, 2012:

(1) 7.4% cumulative persisting annual savings for the year ending December 31, 2018;

(2) 8.2% cumulative persisting annual savings for the year ending December 31, 2019;

(3) 9.0% cumulative persisting annual savings for the year ending December 31, 2020;

(4) 9.8% cumulative persisting annual savings for the year ending December 31, 2021;

(5) 10.6% cumulative persisting annual savings for the year ending December 31, 2022;

(6) 11.4% cumulative persisting annual savings for the year ending December 31, 2023;

(7) 12.2% cumulative persisting annual savings for the year ending December 31, 2024;

(8) 13% cumulative persisting annual savings for the year ending December 31, 2025;

(9) 13.6% cumulative persisting annual savings for the year ending December 31, 2026;

(10) 14.2% cumulative persisting annual savings for the year ending December 31, 2027;

(11) 14.8% cumulative persisting annual savings for the year ending December 31, 2028;

(12) 15.4% cumulative persisting annual savings for the year ending December 31, 2029; and

(13) 16% cumulative persisting annual savings for the year ending December 31, 2030.

The difference between the cumulative persisting annual savings goal for the applicable calendar year and the cumulative persisting annual savings goal for the immediately preceding calendar year is 0.8% for the period of January 1, 2018 through December 31, 2025 and 0.6% for the period of January 1, 2026 through December 31, 2030.

(b-20) Each electric utility subject to this Section may include cost-effective voltage optimization measures in its plans submitted under subsections (f) and (g) of this Section, and the costs incurred by a utility to implement the measures under a Commission-approved plan shall be recovered under the provisions of Article IX or Section 16-108.5 of this Act. For purposes of this Section, the measure life of voltage optimization measures shall be 15 years. The measure life period is independent of the depreciation rate of the voltage optimization assets deployed.

Within 270 days after June 1, 2017 (the effective date of Public Act 99-906), an electric utility that serves less than 3,000,000 retail customers but more than 500,000 retail customers in the State shall file a plan with the Commission that identifies the cost-effective voltage optimization investment the electric utility plans to undertake through December 31, 2024. The Commission, after notice and hearing, shall approve or approve with modification the plan within 120 days after the plan's filing and, in the order approving or approving with modification the plan, the Commission shall adjust the applicable cumulative persisting annual savings goals set forth in subsection (b-15) to reflect any amount of cost-effective energy savings approved by the Commission that is greater than or less than the following cumulative persisting annual savings values attributable to voltage optimization for the applicable year:

(1) 0.0% of cumulative persisting annual savings for the year ending December 31, 2018;

(2) 0.17% of cumulative persisting annual savings for the year ending December 31, 2019;

(3) 0.17% of cumulative persisting annual savings for the year ending December 31, 2020;

(4) 0.33% of cumulative persisting annual savings for the year ending December 31, 2021;

(5) 0.5% of cumulative persisting annual savings for the year ending December 31, 2022;

(6) 0.67% of cumulative persisting annual savings for the year ending December 31, 2023;

(7) 0.83% of cumulative persisting annual savings for the year ending December 31, 2024; and

(8) 1.0% of cumulative persisting annual savings for the year ending December 31, 2025.

(b-25) In the event an electric utility jointly offers an energy efficiency measure or program with a gas utility under plans approved under this Section and Section 8-104 of this Act, the electric utility may continue offering the program, including the gas energy efficiency measures, in the event the gas utility discontinues funding the program. In that event, the energy savings value associated with such other fuels shall be converted to electric energy savings on an equivalent Btu basis for the premises. However, the electric utility shall prioritize programs for low-income residential customers to the extent practicable. An electric utility may recover the costs of offering the gas energy efficiency measures under this subsection (b-25).

For those energy efficiency measures or programs that save both electricity and other fuels but are not jointly offered with a gas utility under plans approved under this Section and Section 8-104 or not offered with an affiliated gas utility under paragraph (6) of subsection (f) of Section 8-104 of this Act, or for those energy efficiency measures that achieve savings of fuels other than electricity, an ~~the~~ electric utility may count savings of fuels other than electricity toward the achievement of its annual savings goal, and the energy savings value associated with such other fuels shall be converted to electric energy savings on an equivalent Btu basis at the premises.

In no event shall more than 10% of each year's applicable annual incremental goal as defined in paragraph (7) of subsection (g) of this Section be met through savings of fuels other than electricity; however, savings of fuels other than electricity achieved by measures that educate about, incentivize, encourage, or otherwise support the use of electricity to power, in whole or in part, vehicles, including, but not limited to, cars, trucks, buses, trains, trolleys, boats, on-road or off-road vehicles, or other equipment or methods of transporting goods or people, shall count towards the applicable annual incremental goal and shall not be included in the 10% limit set forth in this subsection (b-25). Such measures shall include, but are not limited to, measures

<u>that educate about, incentivize, encourage, or otherwise support the adoption of electric vehicles by retail customers of all customer classes</u>.

(c) Electric utilities shall be responsible for overseeing the design, development, and filing of energy efficiency plans with the Commission and may, as part of that implementation, outsource various aspects of program development and implementation. A minimum of 10%, for electric utilities that serve more than 3,000,000 retail customers in the State, and a minimum of 7%, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, of the utility's entire portfolio funding level for a given year shall be used to procure cost-effective energy efficiency measures from units of local government, municipal corporations, school districts, public housing, and community college districts, provided that a minimum percentage of available funds shall be used to procure energy efficiency from public housing, which percentage shall be equal to public housing's share of public building energy consumption.

The utilities shall also implement energy efficiency measures targeted at low-income households, which, for purposes of this Section, shall be defined as households at or below 80% of area median income, and expenditures to implement the measures shall be no less than $25,000,000 per year for electric utilities that serve more than 3,000,000 retail customers in the State and no less than $8,350,000 per year for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State.

Each electric utility shall assess opportunities to implement cost-effective energy efficiency measures and programs through a public housing authority or authorities located in its service territory. If such opportunities are identified, the utility shall propose such measures and programs to address the opportunities. Expenditures to address such opportunities shall be credited toward the minimum procurement and expenditure requirements set forth in this subsection (c).

Implementation of energy efficiency measures and programs targeted at low-income households should be contracted, when it is practicable, to independent third parties that have demonstrated capabilities to serve such households, with a preference for not-for-profit entities and government agencies that have existing relationships with or experience serving low-income communities in the State.

Each electric utility shall develop and implement reporting procedures that address and assist in determining the amount of energy savings that can be applied to the low-income procurement and expenditure requirements set forth in this subsection (c).

The electric utilities shall also convene a low-income energy efficiency advisory committee to assist in the design and evaluation of the low-income energy efficiency programs. The committee shall be comprised of the electric utilities subject to the requirements of this Section, the gas utilities subject to the requirements of Section 8-104 of this Act, the utilities' low-income energy efficiency implementation contractors, and representatives of community-based organizations.

(d) Notwithstanding any other provision of law to the contrary, a utility providing approved energy efficiency measures and, if applicable, demand-response measures in the State shall be permitted to recover all reasonable and prudently incurred costs of those measures from all retail customers, except as provided in subsection (l) of this Section, as follows, provided that nothing in this subsection (d) permits the double recovery of such costs from customers:

(1) The utility may recover its costs through an automatic adjustment clause tariff filed with and approved by the Commission. The tariff shall be established outside the context of a general rate case. Each year the Commission shall initiate a review to reconcile any amounts collected with the actual costs and to determine the required adjustment to the annual tariff factor to match annual expenditures. To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail

customers in the State, the utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

(2) A utility may recover its costs through an energy efficiency formula rate approved by the Commission under a filing under subsections (f) and (g) of this Section, which shall specify the cost components that form the basis of the rate charged to customers with sufficient specificity to operate in a standardized manner and be updated annually with transparent information that reflects the utility's actual costs to be recovered during the applicable rate year, which is the period beginning with the first billing day of January and extending through the last billing day of the following December. The energy efficiency formula rate shall be implemented through a tariff filed with the Commission under subsections (f) and (g) of this Section that is consistent with the provisions of this paragraph (2) and that shall be applicable to all delivery services customers. The Commission shall conduct an investigation of the tariff in a manner consistent with the provisions of this paragraph (2), subsections (f) and (g) of this Section, and the provisions of Article IX of this Act to the extent they do not conflict with this paragraph (2). The energy efficiency formula rate approved by the

Commission shall remain in effect at the discretion of the utility and shall do the following:

(A) Provide for the recovery of the utility's actual costs incurred under this Section that are prudently incurred and reasonable in amount consistent with Commission practice and law. The sole fact that a cost differs from that incurred in a prior calendar year or that an investment is different from that made in a prior calendar year shall not imply the imprudence or unreasonableness of that cost or investment.

(B) Reflect the utility's actual year-end capital structure for the applicable calendar year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law. To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, a participating electric utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

(C) Include a cost of equity, which <u>in all rate years for electric utilities that serve 3,000,000 or more retail customers in this State, and in each rate</u>

year commencing before December 1, 2019 for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, shall be calculated as the sum of the following:

(i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and

(ii) 580 basis points.

For electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, for each rate year commencing after November 30, 2019, the cost of equity shall be calculated as the sum of the following: (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and (ii) 680 basis points; however, if the cost of equity as calculated under this subparagraph (C) of this paragraph (2) for each rate year commencing after November 30, 2019, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State is greater than the national average cost of equity for the rate year by 50 basis points or more, then the Illinois Commerce Commission shall include a cost of equity at a rate equal to the national average cost of equity as calculated under this subparagraph (C) of this paragraph (2) plus 50 basis points. For purposes of this subparagraph (C) of this paragraph (2), the national average cost of equity for a rate year shall be the simple average of the cost of equity approved in each order of a state regulatory commission, other than the Commission, issued during that rate year that is applicable to retail electric service provided by an investor-owned public utility company operating in the United States. No order shall be excluded from the national average cost of equity calculated under this subparagraph (C) of this paragraph (2) on the grounds that it is subject to rehearing or appeal. In the hearing during the first rate year commencing after November 30, 2019, the Commission shall set the cost of equity using the method applicable to rate years commencing prior to December 1, 2019. In the hearings in rate years subsequent to such first rate year, the Commission shall set the cost of equity using the method applicable to rate years commencing after November 30, 2019, including the reconciliation of the first rate

<u>year commencing after November 30, 2019. If, for any rate year, there are fewer than 15 applicable orders of state regulatory commissions with which to compute the average cost of equity under this subparagraph (C) of this paragraph (2), the Commission shall include in the calculation of the national average the number of state regulatory orders from the prior year or years necessary to reach a total of 15, beginning with the most recently issued and proceeding in reverse chronological order.</u>

At such time as the Board of Governors of the Federal Reserve System ceases to include the monthly average yields of 30-year U.S. Treasury bonds in its weekly H.15 Statistical Release or successor publication, the monthly average yields of the U.S. Treasury bonds then having the longest duration published by the Board of Governors in its weekly H.15 Statistical Release or successor publication shall instead be used for purposes of this paragraph (2).

(D) Permit and set forth protocols, subject to a determination of prudence and reasonableness consistent with Commission practice and law, for the following:

(i) recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance; however, this protocol shall not apply if such expense related to costs incurred under this Section is recovered under Article IX or Section 16-108.5 of this Act; incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the energy efficiency formula rate;

(ii) recovery of pension and other post-employment benefits expense, provided that such costs are supported by an actuarial study; however, this protocol shall not apply if such expense related to costs incurred under this Section is recovered under Article IX or Section 16-108.5 of this Act;

(iii) recovery of existing regulatory assets over the periods previously authorized by the Commission;

(iv) as described in subsection (e), amortization of costs incurred under this Section; and

(v) projected, weather normalized billing determinants for the applicable rate year.

(E) Provide for an annual reconciliation, as described in paragraph (3) of this subsection (d), less any deferred taxes related to the reconciliation, with interest at an annual rate of return equal to the utility's weighted average cost of capital, including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return, of the energy efficiency revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its energy efficiency formula rate tariff under this paragraph (2), with what the revenue requirement would have been had the actual cost information for the applicable calendar year been available at the filing date.

The utility shall file, together with its tariff, the projected costs to be incurred by the utility during the rate year under the utility's multi-year plan approved under subsections (f) and (g) of this Section, including, but not limited to, the projected capital investment costs and projected regulatory asset balances with correspondingly updated depreciation and amortization reserves and expense, that shall populate the energy efficiency formula rate and set the initial rates under the formula.

The Commission shall review the proposed tariff in conjunction with its review of a proposed multi-year plan, as specified in paragraph (5) of subsection (g) of this Section. The review shall be based on the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, the Commission applies in a hearing to review a filing for a general increase in rates under Article IX of this Act. The initial rates shall take effect beginning with the January monthly billing period following the Commission's approval.

The tariff's rate design and cost allocation across customer classes shall be consistent with the utility's automatic adjustment clause tariff in effect on June 1, 2017 (the effective date of Public Act 99-906); however, the Commission may revise the tariff's rate design and cost allocation in subsequent proceedings under paragraph (3) of this subsection (d).

If the energy efficiency formula rate is terminated, the then current rates shall remain in effect until such time as the energy efficiency costs are incorporated into new rates that are set under this subsection (d) or Article IX of this Act, subject to retroactive rate adjustment, with interest, to reconcile rates charged with actual costs.

(3) The provisions of this paragraph (3) shall only apply to an electric utility that has elected to file an energy efficiency formula rate under paragraph (2) of this

subsection (d). Subsequent to the Commission's issuance of an order approving the utility's energy efficiency formula rate structure and protocols, and initial rates under paragraph (2) of this subsection (d), the utility shall file, on or before June 1 of each year, with the Chief Clerk of the Commission its updated cost inputs to the energy efficiency formula rate for the applicable rate year and the corresponding new charges, as well as the information described in paragraph (9) of subsection (g) of this Section. Each such filing shall conform to the following requirements and include the following information:

(A) The inputs to the energy efficiency formula rate for the applicable rate year shall be based on the projected costs to be incurred by the utility during the rate year under the utility's multi-year plan approved under subsections (f) and (g) of this Section, including, but not limited to, projected capital investment costs and projected regulatory asset balances with correspondingly updated depreciation and amortization reserves and expense. The filing shall also include a reconciliation of the energy efficiency revenue requirement that was in effect for the prior rate year (as set by the cost inputs for the prior rate year) with the actual revenue requirement for the prior rate year (determined using a year-end rate base) that uses amounts reflected in the applicable FERC Form 1 that reports the actual costs for the prior rate year. Any over-collection or under-collection indicated by such reconciliation shall be reflected as a credit against, or recovered as an additional charge to, respectively, with interest calculated at a rate equal to the utility's weighted average cost of capital approved by the Commission for the prior rate year, the charges for the applicable rate year. Such over-collection or under-collection shall be adjusted to remove any deferred taxes related to the reconciliation, for purposes of calculating interest at an annual rate of return equal to the utility's weighted average cost of capital approved by the Commission for the prior rate year, including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return. Each reconciliation shall be certified by the participating utility in the same manner that FERC Form 1 is certified. The filing shall also include the charge or credit, if any, resulting from the calculation required by subparagraph (E) of paragraph (2) of this subsection (d).

Notwithstanding any other provision of law to the contrary, the intent of the reconciliation is to ultimately reconcile both the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its energy efficiency formula rate tariff under paragraph (2) of this subsection (d), with what the revenue requirement determined using a year-end rate base for the applicable calendar year would have been had the actual cost information for the applicable calendar year been available at the filing date.

For purposes of this Section, "FERC Form 1" means the Annual Report of Major Electric Utilities, Licensees and Others that electric utilities are required to file with the Federal Energy Regulatory Commission under the Federal Power Act, Sections 3, 4(a), 304 and 209, modified as necessary to be consistent with 83 Ill. Admin. Code Part 415 as of May 1, 2011. Nothing in this Section is intended to allow costs that are not otherwise recoverable to be recoverable by virtue of inclusion in FERC Form 1.

(B) The new charges shall take effect beginning on the first billing day of the following January billing period and remain in effect through the last billing day of the next December billing period regardless of whether the Commission enters upon a hearing under this paragraph (3).

(C) The filing shall include relevant and necessary data and documentation for the applicable rate year. Normalization adjustments shall not be required.

Within 45 days after the utility files its annual update of cost inputs to the energy efficiency formula rate, the Commission shall with reasonable notice, initiate a proceeding concerning whether the projected costs to be incurred by the utility and recovered during the applicable rate year, and that are reflected in the inputs to the energy efficiency formula rate, are consistent with the utility's approved multi-year plan under subsections (f) and (g) of this Section and whether the costs incurred by the utility during the prior rate year were prudent and reasonable. The Commission shall also have the authority to investigate the information and data described in paragraph (9) of subsection (g) of this Section, including the proposed adjustment to the utility's return on equity component of its weighted average cost of capital. During the course of the proceeding, each objection shall be stated with particularity and evidence provided in support thereof, after which the utility shall have the opportunity to rebut the evidence. Discovery shall be allowed consistent with the Commission's Rules of Practice, which Rules of Practice shall be enforced by the Commission or the assigned administrative law judge. The Commission shall apply the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, during the proceeding as it would apply in a proceeding to review a filing for a general increase in rates under Article IX of this Act. The Commission shall not, however, have the authority in a proceeding under this paragraph (3) to consider or order any changes to the structure or protocols of the energy efficiency formula rate approved under paragraph (2) of this subsection (d). In a proceeding under this paragraph (3), the Commission shall enter its order no later than the earlier of 195 days after the utility's filing of its annual update of cost inputs to the energy efficiency formula rate or December 15. The utility's proposed return on equity calculation, as described in paragraphs (7) through (9) of subsection (g) of this Section, shall be deemed the final, approved calculation on December 15 of the year in which it is filed unless the Commission enters an order on or before December 15, after notice and hearing, that modifies such calculation consistent with this Section. The Commission's determinations of the prudence and reasonableness of the costs incurred, and determination of such return on equity calculation, for the applicable calendar year shall be final upon entry of the Commission's order and shall not be subject to reopening, reexamination, or collateral attack in any other

Commission proceeding, case, docket, order, rule, or regulation; however, nothing in this paragraph (3) shall prohibit a party from petitioning the Commission to rehear or appeal to the courts the order under the provisions of this Act.

(e) Beginning on June 1, 2017 (the effective date of Public Act 99-906), a utility subject to the requirements of this Section may elect to defer, as a regulatory asset, up to the full amount of its expenditures incurred under this Section for each annual period, including, but not limited to, any expenditures incurred above the funding level set by subsection (f) of this Section for a given year. The total expenditures deferred as a regulatory asset in a given year shall be amortized and recovered over a period that is equal to the weighted average of the energy efficiency measure lives implemented for that year that are reflected in the regulatory asset. The unamortized balance shall be recognized as of December 31 for a given year. The utility shall also earn a return on the total of the unamortized balances of all of the energy efficiency regulatory assets, less any deferred taxes related to those unamortized balances, at an annual rate equal to the utility's weighted average cost of capital that includes, based on a year-end capital structure, the utility's actual cost of debt for the applicable calendar year and a cost of equity, which shall be calculated in accordance with the calculations set forth in subparagraph (C) of paragraph (2) of subsection (d) of this Section ~~as the sum of the (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and (ii) 580 basis points~~, including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return. Capital investment costs shall be depreciated and recovered over their useful lives consistent with generally accepted accounting principles. The weighted average cost of capital shall be applied to the capital investment cost balance, less any accumulated depreciation and accumulated deferred income taxes, as of December 31 for a given year.

When an electric utility creates a regulatory asset under the provisions of this Section, the costs are recovered over a period during which customers also receive a benefit which is in the public interest. Accordingly, it is the intent of the General Assembly that an electric utility that elects to create a regulatory asset under the provisions of this Section shall recover all of the associated costs as set forth in this Section. After the Commission has approved the prudence and reasonableness of the costs that comprise the regulatory asset, the electric utility shall be permitted to recover all such costs, and the value and recoverability through rates of the associated regulatory asset shall not be limited, altered, impaired, or reduced.

(f) Beginning in 2017, each electric utility shall file an energy efficiency plan with the Commission to meet the energy efficiency standards for the next applicable multi-year period beginning January 1 of the year following the filing, according to the schedule set forth in paragraphs (1) through (3) of this subsection (f). If a utility does not file such a plan on or before the applicable filing deadline for the plan, it shall face a penalty of $100,000 per day until the plan is filed.

(1) No later than 30 days after June 1, 2017 (the effective date of Public Act 99-906), each electric utility shall file a 4-year energy efficiency plan commencing on January 1, 2018 that is designed to achieve the cumulative persisting annual savings goals specified in paragraphs (1) through (4) of subsection (b-5) of this Section or in paragraphs (1) through (4) of subsection (b-15) of this Section, as applicable, through implementation of energy efficiency measures; however, the goals may be reduced if the utility's expenditures are limited pursuant to subsection (m) of this Section or, for a utility that serves less than 3,000,000 retail customers, if each of the following conditions are met: (A) the plan's analysis and forecasts of the utility's ability to acquire energy savings demonstrate that achievement of such goals is not cost effective; and (B) the amount of energy savings achieved by the utility as determined by the independent

evaluator for the most recent year for which savings have been evaluated preceding the plan filing was less than the average annual amount of savings required to achieve the goals for the applicable 4-year plan period. Except as provided in subsection (m) of this Section, annual increases in cumulative persisting annual savings goals during the applicable 4-year plan period shall not be reduced to amounts that are less than the maximum amount of cumulative persisting annual savings that is forecast to be cost-effectively achievable during the 4-year plan period. The Commission shall review any proposed goal reduction as part of its review and approval of the utility's proposed plan.

(2) No later than March 1, 2021, each electric utility shall file a 4-year energy efficiency plan commencing on January 1, 2022 that is designed to achieve the cumulative persisting annual savings goals specified in paragraphs (5) through (8) of subsection (b-5) of this Section or in paragraphs (5) through (8) of subsection (b-15) of this Section, as applicable, through implementation of energy efficiency measures; however, the goals may be reduced if the utility's expenditures are limited pursuant to subsection (m) of this Section or, each of the following conditions are met: (A) the plan's analysis and forecasts of the utility's ability to acquire energy savings demonstrate that achievement of such goals is not cost

effective; and (B) the amount of energy savings achieved by the utility as determined by the independent evaluator for the most recent year for which savings have been evaluated preceding the plan filing was less than the average annual amount of savings required to achieve the goals for the applicable 4-year plan period. Except as provided in subsection (m) of this Section, annual increases in cumulative persisting annual savings goals during the applicable 4-year plan period shall not be reduced to amounts that are less than the maximum amount of cumulative persisting annual savings that is forecast to be cost-effectively achievable during the 4-year plan period. The Commission shall review any proposed goal reduction as part of its review and approval of the utility's proposed plan.

(3) No later than March 1, 2025, each electric utility shall file a 5-year energy efficiency plan commencing on January 1, 2026 that is designed to achieve the cumulative persisting annual savings goals specified in paragraphs (9) through (13) of subsection (b-5) of this Section or in paragraphs (9) through (13) of subsection (b-15) of this Section, as applicable, through implementation of energy efficiency measures; however, the goals may be reduced if the utility's expenditures are limited pursuant to subsection (m) of this Section or, each of the following conditions are met: (A) the plan's analysis and forecasts

of the utility's ability to acquire energy savings demonstrate that achievement of such goals is not cost effective; and (B) the amount of energy savings achieved by the utility as determined by the independent evaluator for the most recent year for which savings have been evaluated preceding the plan filing was less than the average annual amount of savings required to achieve the goals for the applicable 5-year plan period. Except as provided in subsection (m) of this Section, annual increases in cumulative persisting annual savings goals during the applicable 5-year plan period shall not be reduced to amounts that are less than the maximum amount of cumulative persisting annual savings that is forecast to be cost-effectively achievable during the 5-year plan period. The Commission shall review any proposed goal reduction as part of its review and approval of the utility's proposed plan.

Each utility's plan shall set forth the utility's proposals to meet the energy efficiency standards identified in subsection (b-5) or (b-15), as applicable and as such standards may have been modified under this subsection (f), taking into account the unique circumstances of the utility's service territory. For those plans commencing on January 1, 2018, the Commission shall seek public comment on the utility's plan and shall issue an order approving or disapproving each plan no later than 105 days after June 1, 2017 (the effective date of

Public Act 99-906). For those plans commencing after December 31, 2021, the Commission shall seek public comment on the utility's plan and shall issue an order approving or disapproving each plan within 6 months after its submission. If the Commission disapproves a plan, the Commission shall, within 30 days, describe in detail the reasons for the disapproval and describe a path by which the utility may file a revised draft of the plan to address the Commission's concerns satisfactorily. If the utility does not refile with the Commission within 60 days, the utility shall be subject to penalties at a rate of $100,000 per day until the plan is filed. This process shall continue, and penalties shall accrue, until the utility has successfully filed a portfolio of energy efficiency and demand-response measures. Penalties shall be deposited into the Energy Efficiency Trust Fund.

(g) In submitting proposed plans and funding levels under subsection (f) of this Section to meet the savings goals identified in subsection (b-5) or (b-15) of this Section, as applicable, the utility shall:

(1) Demonstrate that its proposed energy efficiency measures will achieve the applicable requirements that are identified in subsection (b-5) or (b-15) of this Section, as modified by subsection (f) of this Section.

(2) Present specific proposals to implement new building and appliance standards that have been placed into effect.

(3) Demonstrate that its overall portfolio of measures, not including low-income programs described in subsection (c) of this Section, is cost-effective using the total resource cost test or complies with paragraphs (1) through (3) of subsection (f) of this Section and represents a diverse cross-section of opportunities for customers of all rate classes, other than those customers described in subsection (l) of this Section, to participate in the programs. Individual measures need not be cost effective.

(4) Present a third-party energy efficiency implementation program subject to the following requirements:

(A) beginning with the year commencing January 1, 2019, electric utilities that serve more than 3,000,000 retail customers in the State shall fund third-party energy efficiency programs in an amount that is no less than $25,000,000 per year, and electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State shall fund third-party energy efficiency programs in an amount that is no less than $8,350,000 per year;

(B) during 2018, the utility shall conduct a solicitation process for purposes of requesting proposals from third-party vendors for those third-party energy efficiency programs to be offered during one or more of the years commencing January 1, 2019, January 1, 2020, and January 1, 2021; for those multi-year plans commencing on January 1, 2022 and January 1, 2026, the utility shall conduct a solicitation process during 2021 and 2025, respectively, for purposes of requesting proposals from third-party vendors for those third-party energy efficiency programs to be offered during one or more years of the respective multi-year plan period; for each solicitation process, the utility shall identify the sector, technology, or geographical area for which it is seeking requests for proposals;

(C) the utility shall propose the bidder qualifications, performance measurement process, and contract structure, which must include a performance payment mechanism and general terms and conditions; the proposed qualifications, process, and structure shall be subject to Commission approval; and

(D) the utility shall retain an independent third party to score the proposals received through the solicitation process described in this paragraph (4), rank them according to their cost per lifetime kilowatt-hours saved, and assemble the portfolio of third-party programs.

The electric utility shall recover all costs associated with Commission-approved, third-party administered programs regardless of the success of those programs.

(4.5) Implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement continues until December 31, 2026.

(5) Include a proposed or revised cost-recovery tariff mechanism, as provided for under subsection (d) of this Section, to fund the proposed energy efficiency and demand-response measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs.

(6) Provide for an annual independent evaluation of the performance of the cost-effectiveness of the utility's portfolio of measures, as well as a full review of the multi-year plan results of the broader net program impacts and, to the extent practical, for adjustment of the measures on a going-forward basis as a result of the evaluations. <u>For purposes of evaluating the cost-effectiveness of measures that incentivize, encourage, or otherwise support the purchase of vehicles</u>

that use electricity for power, in whole or in part, including, but not limited to, cars, trucks, buses, trains, trolleys, boats, on-road or off-road vehicles, or other equipment or methods of transporting goods or people, including, but not limited to, measures that incentivize, encourage, or otherwise support the adoption of electric vehicles by retail customers of all customer classes, the independent evaluation shall include valuation and consideration of the reduction of carbon emissions and avoided costs associated with the reduction in fossil fuel consumption associated with the measures. The resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given year.

(7) For electric utilities that serve more than 3,000,000 retail customers in the State:

(A) Through December 31, 2025, provide for an adjustment to the return on equity component of the utility's weighted average cost of capital calculated under subsection (d) of this Section:

(i) If the independent evaluator determines that the utility achieved a cumulative persisting annual savings that is less than the applicable annual incremental goal, then the return on equity component shall be reduced by a maximum of 200 basis points in the event that the utility achieved no more than 75% of such goal. If the utility achieved more than 75% of the applicable annual incremental goal but less than 100% of such goal, then the return on equity component shall be reduced by 8 basis points for each percent by which the utility failed to achieve the goal.

(ii) If the independent evaluator determines that the utility achieved a cumulative persisting annual savings that is more than the applicable annual incremental goal, then the return on equity component shall be increased by a maximum of 200 basis points in the event that the utility achieved at least 125% of such goal. If the utility achieved more than 100% of the applicable annual incremental goal but less than 125% of such goal, then the return on equity component shall be increased by 8 basis points for each percent by which the utility achieved above the goal. If the applicable annual incremental goal was reduced under paragraphs (1) or (2) of subsection (f) of this Section, then the following adjustments shall be made to the calculations described in this item (ii):

(aa) the calculation for determining achievement that is at least 125% of the applicable annual incremental goal shall use the unreduced applicable annual incremental goal to set the value; and

(bb) the calculation for determining achievement that is less than 125% but more than 100% of the applicable annual incremental goal shall use the reduced applicable annual incremental goal to set the value for 100% achievement of the goal and shall use the unreduced goal to set the value for 125% achievement. The 8 basis point value shall also be modified, as necessary, so that the 200 basis points are evenly apportioned among each percentage point value between 100% and 125% achievement.

(B) For the period January 1, 2026 through December 31, 2030, provide for an adjustment to the return on equity component of the utility's weighted average cost of capital calculated under subsection (d) of this Section:

(i) If the independent evaluator determines that the utility achieved a cumulative persisting annual savings that is less than the applicable annual incremental goal, then the return on equity component shall be reduced by a maximum of 200 basis points in the event that the utility achieved no more than 66% of such goal. If the utility achieved more than 66% of the applicable annual incremental goal but less than 100% of such goal, then the return on equity component shall be reduced by 6 basis points for each percent by which the utility failed to achieve the goal.

(ii) If the independent evaluator determines that the utility achieved a cumulative persisting annual savings that is more than the applicable annual incremental goal, then the return on equity component shall be increased by a maximum of 200 basis points in the event that the utility achieved at least 134% of such goal. If the utility achieved more than 100% of the applicable annual incremental goal but less than 134% of such goal, then the return on equity component shall be increased by 6 basis points for each percent by which the utility achieved above the goal. If the applicable annual incremental goal was reduced under paragraph (3) of subsection (f) of this Section, then the following adjustments shall be made to the calculations described in this item (ii):

(aa) the calculation for determining achievement that is at least 134% of the applicable annual incremental goal shall use the unreduced applicable annual incremental goal to set the value; and (bb) the calculation for determining achievement that is less than 134% but more than 100% of the applicable annual incremental goal shall use the reduced applicable annual incremental goal to set the value for 100% achievement of the goal and shall use the unreduced goal to set the value for 134% achievement. The 6 basis point value shall also be modified, as necessary, so that the 200 basis points are evenly apportioned among each percentage point value between 100% and 134% achievement.

(7.5) For purposes of this Section, the term "applicable annual incremental goal" means the difference between the cumulative persisting annual savings goal for the calendar year that is the subject of the independent evaluator's determination and the cumulative persisting annual savings goal for the immediately preceding calendar year, as such goals are defined in subsections (b-5) and (b-15) of this Section and as these goals may have been modified as provided for under subsection (b-20) and paragraphs (1) through (3) of subsection (f) of this Section. Under subsections (b), (b-5), (b-10), and (b-15) of this Section, a utility must first replace energy savings from measures that have reached the end of their measure lives and would otherwise have to be replaced to meet the applicable savings goals identified in subsection (b-5) or (b-15) of this Section before any progress towards achievement of its applicable annual incremental goal may be counted. Notwithstanding anything else set forth in this Section, the difference between the actual annual incremental savings achieved in any given year, including the replacement of energy savings from measures that have expired, and the applicable annual incremental goal shall not affect adjustments to the return on equity for subsequent calendar years under this subsection (g).

(8) For electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State:

(A) Through December 31, 2025, the applicable annual incremental goal shall be compared to the annual incremental savings as determined by the independent evaluator.

(i) The return on equity component shall be reduced by 8 basis points for each percent by which the utility did not achieve 84.4% of the applicable annual incremental goal.

(ii) The return on equity component shall be increased by 8 basis points for each percent by which the utility exceeded 100% of the applicable annual incremental goal.

(iii) The return on equity component shall not be increased or decreased if the annual incremental savings as determined by the independent evaluator is greater than 84.4% of the applicable annual incremental goal and less than 100% of the applicable annual incremental goal.

(iv) The return on equity component shall not be increased or decreased by an amount greater than 200 basis points pursuant to this subparagraph (A).

(B) For the period of January 1, 2026 through December 31, 2030, the applicable annual incremental goal shall be compared to the annual incremental savings as determined by the independent evaluator.

(i) The return on equity component shall be reduced by 6 basis points for each percent by which the utility did not achieve 100% of the applicable annual incremental goal.

(ii) The return on equity component shall be increased by 6 basis points for each percent by which the utility exceeded 100% of the applicable annual incremental goal.

(iii) The return on equity component shall not be increased or decreased by an amount greater than 200 basis points pursuant to this subparagraph (B).

(C) If the applicable annual incremental goal was reduced under paragraphs (1), (2) or (3) of subsection (f) of this Section, then the following adjustments shall be made to the calculations described in subparagraphs (A) and (B) of this paragraph (8):

(i) The calculation for determining achievement that is at least 125% or 134%, as applicable, of the applicable annual incremental goal shall use the unreduced applicable annual incremental goal to set the value.

(ii) For the period through December 31, 2025, the calculation for determining achievement that is less than 125% but more than 100% of the applicable annual incremental goal shall use the reduced applicable annual incremental goal to set the value for 100% achievement of the goal and shall use the unreduced goal to set the value for 125% achievement. The 8 basis point value shall also be modified, as necessary, so that the 200 basis points are evenly apportioned among each percentage point value between 100% and 125% achievement.

(iii) For the period of January 1, 2026 through December 31, 2030, the calculation for determining achievement that is less than 134% but more than 100% of the applicable annual incremental goal shall use the reduced applicable annual incremental goal to set the value for 100% achievement of the goal and shall use the unreduced goal to set the value for 125% achievement. The 6 basis point value shall also be modified, as necessary, so that the 200 basis points are evenly apportioned among each percentage point value between 100% and 134% achievement.

(8.5) Electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State may identify, at the electric utility's sole discretion, cost-effective measures that educate about, incentivize, encourage, or otherwise support the use of electricity to power, in whole or in part, vehicles, including, but not limited to, cars, trucks, buses, trains, trolleys, boats, on-road or off-road vehicles, or other equipment or methods of transporting goods or people. Such measures may include, but are not limited to, measures that educate about, incentivize, encourage, or otherwise support the adoption of electric vehicles by retail customers of all rate classes.

(9) The utility shall submit the energy savings data to the independent evaluator no later than 30 days after the close of the plan year. The independent evaluator shall determine the cumulative persisting annual savings for a given plan year no later than 120 days after the close of

the plan year. The utility shall submit an informational filing to the Commission no later than 160 days after the close of the plan year that attaches the independent evaluator's final report identifying the cumulative persisting annual savings for the year and calculates, under paragraph (7) or (8) of this subsection (g), as applicable, any resulting change to the utility's return on equity component of the weighted average cost of capital applicable to the next plan year beginning with the January monthly billing period and extending through the December monthly billing period. However, if the utility recovers the costs incurred under this Section under paragraphs (2) and (3) of subsection (d) of this Section, then the utility shall not be required to submit such informational filing, and shall instead submit the information that would otherwise be included in the informational filing as part of its filing under paragraph (3) of such subsection (d) that is due on or before June 1 of each year.

For those utilities that must submit the informational filing, the Commission may, on its own motion or by petition, initiate an investigation of such filing, provided, however, that the utility's proposed return on equity calculation shall be deemed the final, approved calculation on December 15 of the year in which it is filed unless the Commission enters an order on or before December 15, after notice and hearing, that modifies such calculation consistent with this Section.

The adjustments to the return on equity component described in paragraphs (7) and (8) of this subsection (g) shall be applied as described in such paragraphs through a separate tariff mechanism, which shall be filed by the utility under subsections (f) and (g) of this Section.

(h) Other than measures authorized by subsection (n) of this Section or identified pursuant to paragraph (8.5) of subsection (g) of this Section, no ~~No~~ more than 6% of energy efficiency and demand-response program revenue may be allocated for research, development, or pilot deployment of new equipment or measures.

(i) When practicable, electric utilities shall incorporate advanced metering infrastructure data into the planning, implementation, and evaluation of energy efficiency measures and programs, subject to the data privacy and confidentiality protections of applicable law.

(j) The independent evaluator shall follow the guidelines and use the savings set forth in Commission-approved energy efficiency policy manuals and technical reference manuals, as each may be updated from time to time. Until such time as measure life values for energy efficiency measures implemented for low-income households under subsection (c) of this Section are incorporated into such Commission-approved manuals, the low-income measures shall have the same measure life values that are established for same measures implemented in households that are not low-income households.

Commencing on the effective date of this amendatory Act of the 101st General Assembly, the following provisions shall apply to electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State:

(1) Starting in the year in which this amendatory Act of the 101st General Assembly takes effect and continuing for a period of 5 calendar years thereafter, the savings achieved by energy efficiency measures authorized by subsection (n) of this Section or identified pursuant to paragraph (8.5) of subsection (g) of this Section, shall be evaluated using the following parameters:

(A) the evaluation shall use a factor of 1.50 lbs of carbon dioxide emitted per kilowatt hour of electric energy used for vehicle operation, adjusted each year starting with the year in which this amendatory Act of the 101st General Assembly takes effect to reflect the annual increase of renewable resource procurement as set forth in subsection (c) of Section 1-75 of the Illinois Power Agency Act;

(B) the evaluation shall use a heat rate of fossil fuel electric generating units of 7,939 Btu per kilowatt hour, adjusted each year starting with the year in which this amendatory Act of the 101st General Assembly takes effect to reflect the annual increase of renewable resource procurement as set forth in subsection (c) of Section 1-75 of the Illinois Power Agency Act;

(C) the evaluation shall include any netting of electricity used by the electric vehicle, as calculated using the parameters provided for in paragraph (2) of this subsection (j);

(D) the evaluation shall use a net to gross ratio of 1.0 for each measure evaluated; and

(E) all savings achieved by the measures evaluated shall persist for the life of the measure, without degradation.

(2) Starting in the year in which this amendatory Act of the 101st General Assembly takes effect and continuing for a period of 5 calendar years thereafter, the savings achieved by energy efficiency measures authorized by subsection (n) of this Section or identified pursuant to paragraph (8.5) of subsection (g) of this Section that are applicable to passenger vehicles shall, in addition to the parameters identified in paragraph (1) of this subsection (j), be evaluated using the following parameters:

(A) the measure life of measures that incentivize or otherwise encourage the purchase of electric vehicles shall be 13 years from the date of original purchase by the customer;

(B) the evaluation shall use a value of 11,500 vehicle miles traveled for annual vehicle operation;

(C) the evaluation shall use a fossil fuel vehicle economy value equal to 28 miles per gallon of fossil fuel used for vehicle operation;

(D) the evaluation shall use a conversion factor of 120,429 Btus per gallon of fossil fuel used for vehicle operation;

(E) the evaluation shall use a factor of 161 lbs of carbon dioxide emitted per million Btu of fossil fuel used for vehicle operation;

(F) the evaluation shall use a factor of 8.78 kg of carbon dioxide emitted per gallon of fossil fuel used for vehicle operation;

(G) the evaluation shall use an annual value of fossil fuel saved of 50 MMBtu; and

(H) the evaluation shall use an electric vehicle efficiency value of 30 kilowatt hours per 100 miles traveled for vehicle operation.

(3) Any additional evaluation criteria not identified in paragraphs (1) or (2) of this subsection (j) used to evaluate savings achieved by energy efficiency measures authorized by subsection (n) of this Section or identified pursuant to paragraph (8.5) of subsection (g) of this Section shall follow the guidelines and use the savings set forth in Commission-approved energy efficiency policy manuals and technical reference manuals, as each may be

updated from time to time.

(k) Notwithstanding any provision of law to the contrary, an electric utility subject to the requirements of this Section may file a tariff cancelling an automatic adjustment clause tariff in effect under this Section or Section 8-103, which shall take effect no later than one business day after the date such tariff is filed. Thereafter, the utility shall be authorized to defer and recover its expenditures incurred under this Section through a new tariff authorized under subsection (d) of this Section or in the utility's next rate case under Article IX or Section 16-108.5 of this Act, with interest at an annual rate equal to the utility's weighted average cost of capital as approved by the Commission in such case. If the utility elects to file a new tariff under subsection (d) of this Section, the utility may file the tariff within 10 days after June 1, 2017 (the effective date of Public Act 99-906), and the cost inputs to such tariff shall be based on the projected costs to be incurred by the utility during the calendar year in which the new tariff is filed and that were not recovered under the tariff that was cancelled as provided for in this subsection. Such costs shall include those incurred or to be incurred by the utility under its multi-year plan approved under subsections (f) and (g) of this Section, including, but not limited to, projected capital investment costs and projected regulatory asset balances with correspondingly updated depreciation and amortization reserves and expense. The Commission shall, after notice and hearing, approve, or approve with modification, such tariff and cost inputs no later than 75 days after the utility filed the tariff, provided that such approval, or approval with modification, shall be consistent with the provisions of this Section to the extent they do not conflict with this subsection (k). The tariff approved by the Commission shall take effect no later than 5 days after the Commission enters its order approving the tariff.

No later than 60 days after the effective date of the tariff cancelling the utility's automatic adjustment clause tariff, the utility shall file a reconciliation that reconciles the moneys collected under its automatic adjustment clause tariff with the costs incurred during the period beginning June 1, 2016 and ending on the date that the electric utility's automatic adjustment clause tariff was cancelled. In the event the reconciliation reflects an under-collection, the utility shall recover the costs as specified in this subsection (k). If the reconciliation reflects an over-collection, the utility shall apply the amount of such over-collection as a one-time credit to retail customers' bills.

(l) For the calendar years covered by a multi-year plan commencing after December 31, 2017, subsections (a) through (j) of this Section do not apply to any retail customers of an electric utility that serves more than 3,000,000 retail customers in the State and whose total highest 30 minute demand was more than 10,000 kilowatts, or any retail customers of an electric utility that serves less than 3,000,000 retail customers but more than 500,000 retail customers in the State and whose total highest 15 minute demand was more than 10,000 kilowatts. For purposes of this subsection (l), "retail customer" has the meaning set forth in Section 16-102 of this Act. A determination of whether this subsection is applicable to a customer shall be made for each multi-year plan beginning after December 31, 2017. The criteria for determining whether this subsection (l) is applicable to a retail customer shall be based on the 12 consecutive billing periods prior to the start of the first year of each such multi-year plan.

(m) Notwithstanding the requirements of this Section, as part of a proceeding to approve a multi-year plan under subsections (f) and (g) of this Section, the Commission shall reduce the amount of energy efficiency measures implemented for any single year, and whose costs are recovered under subsection (d) of this Section, by an amount necessary to limit the estimated average net increase due to the cost of the measures to no more than

(1) 3.5% for each of the 4 years beginning January 1, 2018,

(2) 3.75% for each of the 4 years beginning January 1, 2022, and

(3) 4% for each of the 5 years beginning January 1, 2026,

of the average amount paid per kilowatthour by residential eligible retail customers during calendar year 2015. To determine the total amount that may be spent by an electric utility in any single year, the applicable percentage of the average amount paid per kilowatthour shall be multiplied by the total amount of energy delivered by such electric utility in the calendar year 2015, adjusted to reflect the proportion of the utility's load attributable to customers who are exempt from subsections (a) through (j) of this Section under subsection (l) of this Section. For purposes of this subsection (m), the amount paid per kilowatthour includes, without limitation, estimated amounts paid for supply, transmission, distribution, surcharges, and add-on taxes. For purposes of this Section, "eligible retail customers" shall have the meaning set forth in Section 16-111.5 of this Act. Once the Commission has approved a plan under subsections (f) and (g) of this Section, no subsequent rate impact determinations shall be made.

(n) Starting on the effective date of this amendatory Act of the 101st General Assembly, electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State may administer programs and implement cost-effective measures that educate about, incentivize, encourage, or otherwise support the use of electricity to power, in whole or in part, vehicles, including, but not limited to, cars, trucks, buses, trains, trolleys, boats, on-road or off-road vehicles, or other equipment or methods of transporting goods or people. Such programs and measures may be implemented as part of a plan approved pursuant to subsection (f) of this Section and may include, but are not limited to, measures that educate about, incentivize, encourage, or otherwise support the adoption of electric vehicles by retail customers of all customer classes. Programs and measures authorized by this subsection (n) and identified pursuant to paragraph (8.5) of subsection (g) shall not be prohibited by the Commission as promotional practices under any rules or policies of the Commission, including, but not limited to, 83 Ill. Admin. Code Part 275.

(Source: P.A. 100-840, eff. 8-13-18; 101-81, eff. 7-12-19.)

(220 ILCS 5/8-218 new)

Sec. 8-218. Electric photovoltaic generating facilities.

(a) The General Assembly finds and declares that the citizens and businesses of the State of Illinois would be well-served by the development of photovoltaic electricity production facilities in this State, which would both bring economic benefits and environmental benefits to the State and further expand access to renewable energy resources at an affordable cost to Illinois residents, particularly in those areas of the State that have been significantly and adversely affected by the retirement of coal-fired electric generating plants. To that end, the General Assembly seeks to encourage further development of photovoltaic electric production facilities of all scales in an efficient and cost-effective manner. Accordingly, the General Assembly finds that, notwithstanding other provisions of this Act to the contrary, it would be both prudent and reasonable for electric utilities in this State to plan for, construct, install, control, own, manage, or operate photovoltaic electricity production facilities pursuant to the provisions of this Section.

(b) An electric utility that serves less than 3,000,000 retail customers but more than 500,000 customers in this State, may plan for, construct, install, control, own, manage, or operate photovoltaic electricity production facilities and any energy storage facilities as authorized under Section 16-108.20 of this Act that are planned for, constructed, installed, controlled, owned, managed, or operated in connection with photovoltaic electricity production facilities authorized under this Section without obtaining a certificate of public convenience and necessity pursuant to Section 8-406 of this Act, subject to the following terms and conditions:

(1) the electric utility may plan for, construct, install, control, own, manage, or operate photovoltaic electricity production facilities of any type or scale, including, but not limited to, large scale (greater than 2 MW), small scale (less than or equal to 2 MW) and community solar projects; for purposes of this Section, "community solar projects" includes community solar facilities with a

nameplate capacity up to and including 10,000 kilowatts that are connected to either the distribution system or transmission system of the electric utility;

(2) photovoltaic electricity production facilities authorized pursuant to this Section shall be deemed for all purposes under this Act as prudent and used and useful, including under the provisions of Section 9-212 of this Act, and, subject to the provisions set forth in this Section, the Commission may not limit recovery of any portion of the reasonable costs of the photovoltaic electricity production facilities authorized pursuant to this Section on the grounds that the facilities are not prudent or used and useful;

(3) the electric utility's costs of planning for, constructing, installing, controlling, owning, managing, or operating the photovoltaic electricity production facilities shall be recovered, on a kilowatt hour basis, in the electric utility's rates for delivery service established pursuant to Article XVI or Article IX of this Act, and for purposes of cost recovery the photovoltaic electricity production facilities, shall be treated as distribution assets, provided: (1) the Commission shall have the authority to determine the reasonableness of the costs of the facilities, (2) any monetary value of power and energy from the facilities shall be credited against the delivery services revenue requirement, and (3) all

renewable energy credits associated with the photovoltaic electricity production facilities shall be retired on behalf of the electric utility's distribution customers and may not be sold or used for any other purposes by the electric utility other than satisfying the electric utility's requirements under subsection (c) of Section 1-75 of the Illinois Power Agency Act; and

(4) the annual quantity of renewable energy credits generated from the photovoltaic electricity production facilities placed in service by an electric utility pursuant to this Section after the effective date of this amendatory Act of the 101st General Assembly shall not exceed 20% of the electric utility's requirements under subsection (c) of Section 1-75 of the Illinois Power Agency Act.

For purposes of this Section, "electric utility" has the meaning set forth in Section 16-102 of this Act.

(c) Notwithstanding anything to the contrary in the Illinois Power Agency Act or this Act, the Illinois Power Agency shall apply any renewable energy credits associated with photovoltaic electricity production facilities meeting the criteria set forth in subsection (b) of this Section to the electric utility's requirements under subsection (c) of Section 1-75 of the Illinois Power Agency Act. No cost associated with facilities placed in service pursuant to this Section shall be included when calculating the limitation under subparagraph (E) of paragraph (1) of subsection (c) of Section 1-75 of the Illinois Power Agency Act.

(220 ILCS 5/16-102)

Sec. 16-102. Definitions. For the purposes of this Article the following terms shall be defined as set forth in this Section.

"Alternative retail electric supplier" means every person, cooperative, corporation, municipal corporation, company, association, joint stock company or association, firm, partnership, individual, or other entity, their lessees, trustees, or receivers appointed by any court whatsoever, that offers electric power or energy for sale, lease or in exchange for other value received to one or more retail customers, or that engages in the delivery or furnishing of electric power or energy to such retail customers, and shall include, without limitation, resellers, aggregators and power marketers, but shall not include (i) electric utilities (or any agent of the electric utility to the extent the electric utility provides tariffed services to retail customers through that agent), (ii) any electric cooperative or municipal system as defined in Section 17-100 to the extent that the electric cooperative or municipal system is serving retail customers within any area in which it is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, (iii) a public utility that is owned and operated by any public institution of higher education of this State, or a public utility that is owned by such public institution of higher education and operated by any of its lessees or operating agents, within any area in which it is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, (iv) a retail customer to the extent that customer obtains its electric power and energy from that customer's own cogeneration or self-generation facilities, (v) an entity that owns, operates, sells, or arranges for the installation of a customer's own cogeneration or self-generation facilities, but only to the extent the entity is engaged in owning, selling or arranging for the installation of such facility, or operating the facility on behalf of such customer, provided however that any such third party owner or operator of a facility built after January 1, 1999, complies with the labor provisions of Section 16-128(a) as though such third party were an alternative retail electric supplier, or (vi) an industrial or manufacturing customer that owns its own distribution facilities, to the extent that the customer provides service from that distribution system to a third-party contractor located on the customer's premises that is integrally and predominantly engaged in the customer's industrial or manufacturing process; provided, that if the industrial or manufacturing customer has elected delivery services, the customer shall pay transition charges applicable to the electric power and energy consumed by the third-party contractor unless such charges are otherwise paid by the third party contractor, which shall be calculated based on the usage of, and the base rates or the contract rates applicable to, the third-party contractor in accordance with Section 16-102.

An entity that furnishes the service of charging electric vehicles does not and shall not be deemed to sell electricity and is not and shall not be deemed an alternative retail electric supplier, and is not subject to regulation as such under this Act notwithstanding the basis on which the service is provided or billed. If, however, the entity is otherwise deemed an alternative retail electric supplier under this Act, or is otherwise subject to regulation under this Act, then that entity is not exempt from and remains subject to the otherwise applicable provisions of this Act. The installation, maintenance, and repair of an electric vehicle charging station shall comply with the requirements of subsection (a) of Section 16-128 and Section 16-128A of this Act.

~~For purposes of this Section, the term "electric vehicles" has the meaning ascribed to that term in Section 10 of the Electric Vehicle Act.~~

"Base rates" means the rates for those tariffed services that the electric utility is required to offer pursuant to subsection (a) of Section 16-103 and that were identified in a rate order for collection of the electric utility's base rate revenue requirement, excluding (i) separate automatic rate adjustment riders then in effect, (ii) special or negotiated contract rates, (iii) delivery services tariffs filed pursuant to Section 16-108, (iv) real-time pricing, or (v) tariffs that were in effect prior to October 1, 1996 and that based charges for services on an index or average of other utilities' charges, but including (vi) any subsequent redesign of such rates for tariffed services that is authorized by the Commission after notice and hearing.

"Competitive service" includes (i) any service that has been declared to be competitive pursuant to Section 16-113 of this Act, (ii) contract service, and (iii) services, other than tariffed services, that are related to, but not necessary for, the provision of electric power and energy or delivery services.

"Contract service" means (1) services, including the provision of electric power and energy or other services, that are provided by mutual agreement between an electric utility and a retail customer that is located in the electric utility's service area, provided that, delivery services shall not be a contract service until such services are declared competitive pursuant to Section 16-113; and also means (2) the provision of electric power and energy by an electric utility to retail customers outside the electric utility's service area pursuant to Section 16-116. Provided, however, contract service does not include electric utility services provided pursuant to (i) contracts that retail customers are required to execute as a condition of receiving tariffed services, or (ii) special or negotiated rate contracts for electric utility services that were entered into between an electric utility and a retail customer prior to the effective date of this amendatory Act of 1997 and filed with the Commission.

"Delivery services" means those services provided by the electric utility that are necessary in order for the transmission and distribution systems to function so that retail customers located in the electric utility's service area can receive electric power and energy from suppliers other than the electric utility, and shall include, without limitation, standard metering and billing services.

"Electric utility" means a public utility, as defined in Section 3-105 of this Act, that has a franchise, license, permit or right to furnish or sell electricity to retail customers within a service area.

"Electric vehicle" means: (i) a battery-powered vehicle operated solely by electricity that can be recharged from an external source; or (ii) a plug-in hybrid electric vehicle that operates on electricity and another fuel and has a battery that can be recharged from an external source.

"Electric vehicle charging station" means any facility, infrastructure, or equipment that is used to charge a battery or other energy storage device of an electric vehicle.

"Energy storage" or "storage" means any infrastructure, facility, technology, or device used to store energy for use on an electric distribution or transmission system and shall not include or be considered energy generation.

"Mandatory transition period" means the period from the effective date of this amendatory Act of 1997 through January 1, 2007.

"Municipal system" shall have the meaning set forth in Section 17-100.

"Real-time pricing" means tariffed retail charges for delivered electric power and energy that vary hour-to-hour and are determined from wholesale market prices using a methodology approved by the Illinois Commerce Commission.

"Retail customer" means a single entity using electric power or energy at a single premises and that (A) either (i) is receiving or is eligible to receive tariffed services from an electric utility, or (ii) that is served by a municipal system or electric cooperative within any area in which the municipal system or electric cooperative is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, or (B) an entity which on the effective date of this Act was receiving electric service from a public utility and (i) was engaged in the practice of resale and redistribution of such electricity within a building prior to January 2, 1957, or (ii) was providing lighting services to tenants in a multi-occupancy building, but only to the extent such resale, redistribution or lighting service is authorized by the electric utility's tariffs that were on file with the Commission on the effective date of this Act.

"Service area" means (i) the geographic area within which an electric utility was lawfully entitled to provide electric power and energy to retail customers as of the effective date of this amendatory Act of 1997, and includes (ii) the location of any retail customer to which the electric utility was lawfully providing electric utility services on such effective date.

"Small commercial retail customer" means those nonresidential retail customers of an electric utility consuming 15,000 kilowatt-hours or less of electricity annually in its service area.

"Tariffed service" means services provided to retail customers by an electric utility as defined by its rates on file with the Commission pursuant to the provisions of Article IX of this Act, but shall not include competitive services.

"Transition charge" means a charge expressed in cents per kilowatt-hour that is calculated for a customer or class of customers as follows for each year in which an electric utility is entitled to recover transition charges as provided in Section 16-108:

(1) the amount of revenue that an electric utility would receive from the retail customer or customers if it were serving such customers' electric power and energy requirements as a tariffed service based on (A) all of the

customers' actual usage during the 3 years ending 90 days prior to the date on which such customers were first eligible for delivery services pursuant to Section 16-104, and (B) on (i) the base rates in effect on October 1, 1996 (adjusted for the reductions required by subsection (b) of Section 16-111, for any reduction resulting from a rate decrease under Section 16-101(b), for any restatement of base rates made in conjunction with an elimination of the fuel adjustment clause pursuant to subsection (b), (d), or (f) of Section 9-220 and for any removal of decommissioning costs from base rates pursuant to Section 16-114) and any separate automatic rate adjustment riders (other than a decommissioning rate as defined in Section 16-114) under which the customers were receiving or, had they been customers, would have received electric power and energy from the electric utility during the year immediately preceding the date on which such customers were first eligible for delivery service pursuant to Section 16-104, or (ii) to the extent applicable, any contract rates, including contracts or rates for consolidated or aggregated billing, under which such customers were receiving electric power and energy from the electric utility during such year;

(2) less the amount of revenue, other than revenue from transition charges and decommissioning rates, that the electric utility would receive from such retail customers

for delivery services provided by the electric utility, assuming such customers were taking delivery services for all of their usage, based on the delivery services tariffs in effect during the year for which the transition charge is being calculated and on the usage identified in paragraph (1);

(3) less the market value for the electric power and energy that the electric utility would have used to supply all of such customers' electric power and energy requirements, as a tariffed service, based on the usage identified in paragraph (1), with such market value determined in accordance with Section 16-112 of this Act;

(4) less the following amount which represents the amount to be attributed to new revenue sources and cost reductions by the electric utility through the end of the period for which transition costs are recovered pursuant to Section 16-108, referred to in this Article XVI as a "mitigation factor":

(A) for nonresidential retail customers, an amount equal to the greater of (i) 0.5 cents per kilowatt-hour during the period October 1, 1999 through December 31, 2004, 0.6 cents per kilowatt-hour in calendar year 2005, and 0.9 cents per kilowatt-hour in calendar year 2006, multiplied in each year by the usage identified in paragraph (1), or (ii) an amount equal to the following percentages of the amount produced by applying the applicable base rates (adjusted as described in subparagraph (1)(B)) or contract rate to the usage identified in paragraph (1): 8% for the period October 1, 1999 through December 31, 2002, 10% in calendar years 2003 and 2004, 11% in calendar year 2005 and 12% in calendar year 2006; and

(B) for residential retail customers, an amount equal to the following percentages of the amount produced by applying the base rates in effect on October 1, 1996 (adjusted as described in subparagraph (1)(B)) to the usage identified in paragraph (1): (i) 6% from May 1, 2002 through December 31, 2002, (ii) 7% in calendar years 2003 and 2004, (iii) 8% in calendar year 2005, and (iv) 10% in calendar year 2006;

(5) divided by the usage of such customers identified in paragraph (1),

provided that the transition charge shall never be less than zero.

"Unbundled service" means a component or constituent part of a tariffed service which the electric utility subsequently offers separately to its customers.

(Source: P.A. 97-1128, eff. 8-28-12.)

(220 ILCS 5/16-107.6)

Sec. 16-107.6. Distributed generation rebate.

(a) In this Section:

"Smart inverter" means a device that converts direct current into alternating current and can autonomously contribute to grid support during excursions from normal operating voltage and frequency conditions by providing each of the following: dynamic reactive and real power support, voltage and frequency ride-through, ramp rate controls, communication systems with ability to accept external commands, and other functions from the electric utility.

"Subscriber" has the meaning set forth in Section 1-10 of the Illinois Power Agency Act.

"Subscription" has the meaning set forth in Section 1-10 of the Illinois Power Agency Act.

"Threshold date" means the date on which the load of an electricity provider's net metering customers equals 5% of the total peak demand supplied by that electricity provider during the previous year, as specified under subsection (j) of Section 16-107.5 of this Act.

(b) An electric utility that serves more than 200,000 customers in the State shall file a petition with the Commission requesting approval of the utility's tariff to provide a rebate to a retail customer who owns or operates distributed generation that meets the following criteria:

(1) has a nameplate generating capacity no greater than 2,000 kilowatts and is primarily used to offset that customer's electricity load;

(2) is located on the customer's premises, for the

customer's own use, and not for commercial use or sales, including, but not limited to, wholesale sales of electric power and energy;

(3) is located in the electric utility's service territory; and

(4) is interconnected under rules adopted by the Commission by means of the inverter or smart inverter required by this Section, as applicable.

For purposes of this Section, "distributed generation" shall satisfy the definition of distributed renewable energy generation device set forth in Section 1-10 of the Illinois Power Agency Act to the extent such definition is consistent with the requirements of this Section.

In addition, any new photovoltaic distributed generation that is installed after the effective date of this amendatory Act of the 99th General Assembly must be installed by a qualified person, as defined by subsection (i) of Section 1-56 of the Illinois Power Agency Act.

The tariff shall provide that the utility shall be permitted to operate and control the smart inverter associated with the distributed generation that is the subject of the rebate for the purpose of preserving reliability during distribution system reliability events and shall address the terms and conditions of the operation and the compensation associated with the operation. Nothing in this Section shall negate or supersede Institute of Electrical and Electronics

Engineers interconnection requirements or standards or other similar standards or requirements. The tariff shall also provide for additional uses of the smart inverter that shall be separately compensated and which may include, but are not limited to, voltage and VAR support, regulation, and other grid services. As part of the proceeding described in subsection (e) of this Section, the Commission shall review and determine whether smart inverters can provide any additional uses or services. If the Commission determines that an additional use or service would be beneficial, the Commission shall determine the terms and conditions of the operation and how the use or service should be separately compensated.

(c) The proposed tariff authorized by subsection (b) of this Section shall include the following participation terms and formulae to calculate the value of the rebates to be applied under this Section for distributed generation that satisfies the criteria set forth in subsection (b) of this Section:

(1) Until the utility files its tariff or tariffs to place into effect the rebate values established by the Commission under subsection (e) of this Section, non-residential customers that are taking service under a net metering program offered by an electricity provider under the terms of Section 16-107.5 of this Act may apply for a rebate as provided for in this Section. The value of the rebate shall be $250 per kilowatt of nameplate

generating capacity, measured as nominal DC power output, of a non-residential customer's distributed generation.

(2) After the utility's tariff or tariffs setting the new rebate values established under subsection (d) of this Section take effect, retail customers may, as applicable, make the following elections:

(A) Residential customers that are taking service under a net metering program offered by an electricity provider under the terms of Section 16-107.5 of this Act on the threshold date may elect to either continue to take such service under the terms of such program as in effect on such threshold date for the useful life of the customer's eligible renewable electric generating facility as defined in such Section, or file an application to receive a rebate under the terms of this Section, provided that such application must be submitted within 6 months after the effective date of the tariff approved under subsection (d) of this Section. The value of the rebate shall be the amount established by the Commission and reflected in the utility's tariff pursuant to subsection (e) of this Section.

(B) Non-residential customers that are taking service under a net metering program offered by an electricity provider under the terms of Section 16-107.5 of this Act on the threshold date may apply for a rebate as provided for in this Section. The value of the rebate shall be the amount established by the Commission and reflected in the utility's tariff pursuant to subsection (e) of this Section.

(3) Upon approval of a rebate application submitted under this subsection (c), the retail customer shall no longer be entitled to receive any delivery service credits for the excess electricity generated by its facility and shall be subject to the provisions of subsection (n) of Section 16-107.5 of this Act.

(4) To be eligible for a rebate described in this subsection (c), customers who begin taking service after the effective date of this amendatory Act of the 99th General Assembly under a net metering program offered by an electricity provider under the terms of Section 16-107.5 of this Act must have a smart inverter associated with the customer's distributed generation.

(d) The Commission shall review the proposed tariff submitted under subsections (b) and (c) of this Section and may make changes to the tariff that are consistent with this Section and with the Commission's authority under Article IX of this Act, subject to notice and hearing. Following notice and hearing, the Commission shall issue an order approving, or approving with modification, such tariff no later than 240 days after the utility files its tariff.

(e) When the total generating capacity of the electricity provider's net metering customers is equal to 3%, the Commission shall open an investigation into an annual process and formula for calculating the value of rebates for the retail customers described in subsections (b) and (f) of this Section that submit rebate applications after the threshold date for an electric utility that elected to file a tariff pursuant to this Section. The investigation shall include diverse sets of stakeholders, calculations for valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources. The value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs. No later than 10 days after the Commission enters its final order under this subsection (e), the utility shall file its tariff or tariffs in compliance with the order, and the Commission shall approve, or approve with modification, the tariff or tariffs within 45 days after the utility's filing. For those rebate applications filed after the threshold date but before the utility's tariff or tariffs filed pursuant to this subsection (e) take effect, the value of the rebate shall remain at the value established in subsection (c) of this Section until the tariff is approved.

(f) Notwithstanding any provision of this Act to the contrary, the owner, developer, or subscriber of a generation facility that is part of a net metering program provided under subsection (l) of Section 16-107.5 shall also be eligible to apply for the rebate described in this Section. A subscriber to the generation facility may apply for a rebate in the amount of the subscriber's subscription only if the owner, developer, or previous subscriber to the same panel or panels has not already submitted an application, and, regardless of whether the subscriber is a residential or non-residential customer, may be allowed the amount identified in paragraph (1) of subsection (c) or in subsection (e) of this Section applicable to such customer on the date that the application is submitted. An application for a rebate for a portion of a project described in this subsection (f) may be submitted at or after the time that a related request for net metering is made.

(g) No later than 60 days after the utility receives an application for a rebate under its tariff approved under subsection (d) or (e) of this Section, the utility shall issue a rebate to the applicant under the terms of the tariff. In the event the application is incomplete or the utility is otherwise unable to calculate the payment based on the information provided by the owner, the utility shall issue the payment no later than 60 days after the application is complete or all requested information is received.

(h) An electric utility shall recover from its retail customers all of the costs of the rebates made under a tariff or tariffs placed into effect under this Section, including, but not limited to, the value of the rebates and all costs incurred by the utility to comply with and implement this Section, consistent with the following provisions:

(1) The utility shall defer the full amount of its costs incurred under this Section as a regulatory asset. The total costs deferred as a regulatory asset shall be amortized over a 15-year period. The unamortized balance shall be recognized as of December 31 for a given year. The utility shall also earn a return on the total of the unamortized balance of the regulatory assets, less any deferred taxes related to the unamortized balance, at an annual rate equal to the utility's weighted average cost of capital that includes, based on a year-end capital structure, the utility's actual cost of debt for the applicable calendar year and a cost of equity, which in all rate years for electric utilities that serve more than 3,000,000 retail customers in this State, and in each rate year commencing before December 1, 2019 for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, shall be calculated as the sum of (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15

Statistical Release or successor publication; and (ii) 580 basis points, including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return. <u>For electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State, for each rate year commencing after November 30, 2019, the cost of equity shall be calculated as the sum of the following: (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and (ii) 680 basis points; however, if the cost of equity as calculated under this paragraph (1) for each rate year commencing after November 30, 2019, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State is greater than the national average cost of equity for the rate year by 50 basis points or more, then the Illinois Commerce Commission shall include a cost of equity at a rate equal to the national average cost of equity as calculated under this paragraph (1) plus 50 basis points. For purposes of this paragraph (1), the national average cost of equity for a rate year shall be the simple average of the cost of equity approved in each order of a state regulatory commission, other than</u>

the Commission, issued during that rate year that is applicable to retail electric service provided by an investor-owned public utility company operating in the United States. No order shall be excluded from the national average cost of equity calculated under this paragraph (1) on the grounds that it is subject to rehearing or appeal. In the hearing during the first rate year commencing after November 30, 2019, the Commission shall set the cost of equity using the method applicable to rate years commencing prior to December 1, 2019. In the hearings in rate years subsequent to such first rate year, the Commission shall set the cost of equity using the method applicable to rate years commencing after November 30, 2019, including the reconciliation of the first rate year commencing after November 30, 2019. If, for any rate year, there are fewer than 15 applicable orders of state regulatory commissions with which to compute the average cost of equity, the Commission shall include in the calculation of the national average the number of state regulatory orders from the prior year or years necessary to reach a total of 15, beginning with the most recently issued and proceeding in reverse chronological order.

When an electric utility creates a regulatory asset under the provisions of this Section, the costs are recovered over a period during which customers also receive a benefit, which is in the public interest. Accordingly, it is the intent of the General Assembly that an electric utility that elects to create a regulatory asset under the provisions of this Section shall recover all of the associated costs, including, but not limited to, its cost of capital as set forth in this Section. After the Commission has approved the prudence and reasonableness of the costs that comprise the regulatory asset, the electric utility shall be permitted to recover all such costs, and the value and recoverability through rates of the associated regulatory asset shall not be limited, altered, impaired, or reduced. To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, the utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

(2) The utility, at its election, may recover all of the costs it incurs under this Section as part of a filing for a general increase in rates under Article IX of this Act, as part of an annual filing to update a performance-based formula rate under subsection (d) of Section 16-108.5 of this Act, or through an automatic adjustment clause tariff, provided that nothing in this

paragraph (2) permits the double recovery of such costs from customers. If the utility elects to recover the costs it incurs under this Section through an automatic adjustment clause tariff, the utility may file its proposed tariff together with the tariff it files under subsection (b) of this Section or at a later time. The proposed tariff shall provide for an annual reconciliation, less any deferred taxes related to the reconciliation, with interest at an annual rate of return equal to the utility's weighted average cost of capital as calculated under paragraph (1) of this subsection (h), including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return, of the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its automatic adjustment clause tariff under this subsection (h), with what the revenue requirement would have been had the actual cost information for the applicable calendar year been available at the filing date. The Commission shall review the proposed tariff and may make changes to the tariff that are consistent with this Section and with the Commission's authority under Article IX of this Act, subject to notice and hearing. Following notice and hearing, the Commission shall issue an order approving, or approving with modification, such tariff no later than 240 days after the utility files its tariff.

(i) No later than 90 days after the Commission enters an order, or order on rehearing, whichever is later, approving an electric utility's proposed tariff under subsection (d) of this Section, the electric utility shall provide notice of the availability of rebates under this Section. Subsequent to the utility's notice, any entity that offers in the State, for sale or lease, distributed generation and estimates the dollar saving attributable to such distributed generation shall provide estimates based on both delivery service credits and the rebates available under this Section.

(Source: P.A. 99-906, eff. 6-1-17.)

(220 ILCS 5/16-108.5)

Sec. 16-108.5. Infrastructure investment and modernization; regulatory reform.

(a) (Blank).

(b) For purposes of this Section, "participating utility" means an electric utility or a combination utility serving more than 1,000,000 customers in Illinois that voluntarily elects and commits to undertake (i) the infrastructure investment program consisting of the commitments and obligations described in this subsection (b) and (ii) the customer assistance program consisting of the commitments and obligations described in subsection (b-10) of this Section, notwithstanding any other provisions of this Act and without obtaining any approvals from the Commission or any other agency other than as set forth in this Section, regardless of whether any such approval would otherwise be required. "Combination utility" means a utility that, as of January 1, 2011, provided electric service to at least one million retail customers in Illinois and gas service to at least 500,000 retail customers in Illinois. A participating utility shall recover the expenditures made under the infrastructure investment program through the ratemaking process, including, but not limited to, the performance-based formula rate and process set forth in this Section.

During the infrastructure investment program's peak program year, a participating utility other than a combination utility shall create 2,000 full-time equivalent jobs in Illinois, and a participating utility that is a combination utility shall create 450 full-time equivalent jobs in Illinois related to the provision of electric service. These jobs shall include direct jobs, contractor positions, and induced jobs, but shall not include any portion of a job commitment, not specifically contingent on an amendatory Act of the 97th General Assembly becoming law, between a participating utility and a labor union that existed on December 30, 2011 (the effective date of Public Act 97-646) and that has not yet been fulfilled. A portion of the full-time equivalent jobs created by each participating utility shall include incremental personnel hired subsequent to December 30, 2011 (the effective date of Public Act 97-646). For purposes of this Section, "peak program year" means the consecutive 12-month period with the highest number of full-time equivalent jobs that occurs between the beginning of investment year 2 and the end of investment year 4.

A participating utility shall meet one of the following commitments, as applicable:

(1) Beginning no later than 180 days after a participating utility other than a combination utility files a performance-based formula rate tariff pursuant to subsection (c) of this Section, or, beginning no later than January 1, 2012 if such utility files such performance-based formula rate tariff within 14 days of October 26, 2011 (the effective date of Public Act 97-616), the participating utility shall, except as provided in subsection (b-5):

(A) over a 5-year period, invest an estimated $1,300,000,000 in electric system upgrades, modernization projects, and training facilities, including, but not limited to:

(i) distribution infrastructure improvements totaling an estimated $1,000,000,000, including underground residential distribution cable injection and replacement and mainline cable system refurbishment and replacement projects;

(ii) training facility construction or upgrade projects totaling an estimated $10,000,000, provided that, at a minimum, one such facility shall be located in a municipality having a population of more than 2 million residents and one such facility shall be located in a municipality having a population of more than 150,000 residents but fewer than 170,000 residents; any such new facility located in a municipality having a population of more than 2 million residents must be designed for the purpose of obtaining, and the owner of the facility shall apply for, certification under the United States Green Building Council's Leadership in Energy Efficiency Design Green Building Rating System;

(iii) wood pole inspection, treatment, and replacement programs;

(iv) an estimated $200,000,000 for reducing the susceptibility of certain circuits to storm-related damage, including, but not limited to, high winds, thunderstorms, and ice storms; improvements may include, but are not limited to, overhead to underground conversion and other engineered outcomes for circuits; the participating utility shall prioritize the selection of circuits based on each circuit's historical susceptibility to storm-related damage and the ability to provide the greatest customer benefit upon completion of the improvements; to be eligible for improvement, the participating utility's ability to maintain proper tree clearances surrounding the overhead circuit must not have been impeded by third parties; and

(B) over a 10-year period, invest an estimated $1,300,000,000 to upgrade and modernize its transmission and distribution infrastructure and in Smart Grid electric system upgrades, including, but not limited to:

(i) additional smart meters;

(ii) distribution automation;

(iii) associated cyber secure data communication network; and

(iv) substation micro-processor relay upgrades.

(2) Beginning no later than 180 days after a participating utility that is a combination utility files a performance-based formula rate tariff pursuant to subsection (c) of this Section, or, beginning no later than January 1, 2012 if such utility files such performance-based formula rate tariff within 14 days of October 26, 2011 (the effective date of Public Act 97-616), the participating utility shall, except as provided in subsection (b-5):

(A) over a 10-year period, invest an estimated $265,000,000 in electric system upgrades, modernization projects, and training facilities, including, but not limited to:

(i) distribution infrastructure improvements totaling an estimated $245,000,000, which may include bulk supply substations, transformers, reconductoring, and rebuilding overhead distribution and sub-transmission lines, underground residential distribution cable injection and replacement and mainline cable system refurbishment and replacement projects;

(ii) training facility construction or upgrade projects totaling an estimated $1,000,000; any such new facility must be designed for the purpose of obtaining, and the owner of the facility shall apply for, certification under the United States Green Building Council's Leadership in Energy Efficiency Design Green Building Rating System; and

(iii) wood pole inspection, treatment, and replacement programs; and

(B) over a 10-year period, invest an estimated $360,000,000 to upgrade and modernize its transmission and distribution infrastructure and in Smart Grid electric system upgrades, including, but not limited to:

(i) additional smart meters;

(ii) distribution automation;

(iii) associated cyber secure data communication network; and

(iv) substation micro-processor relay upgrades.

For purposes of this Section, "Smart Grid electric system upgrades" shall have the meaning set forth in subsection (a) of Section 16-108.6 of this Act.

The investments in the infrastructure investment program described in this subsection (b) shall be incremental to the participating utility's annual capital investment program, as defined by, for purposes of this subsection (b), the participating utility's average capital spend for calendar years 2008, 2009, and 2010 as reported in the applicable Federal Energy Regulatory Commission (FERC) Form 1; provided that where one or more utilities have merged, the average capital spend shall be determined using the aggregate of the merged utilities' capital spend reported in FERC Form 1 for the years 2008, 2009, and 2010. A participating utility may add reasonable construction ramp-up and ramp-down time to the investment periods specified in this subsection (b). For each such investment period, the ramp-up and ramp-down time shall not exceed a total of 6 months.

Within 60 days after filing a tariff under subsection (c) of this Section, a participating utility shall submit to the Commission its plan, including scope, schedule, and staffing, for satisfying its infrastructure investment program commitments pursuant to this subsection (b). The submitted plan shall include a schedule and staffing plan for the next calendar year. The plan shall also include a plan for the creation, operation, and administration of a Smart Grid test bed as described in subsection (c) of Section 16-108.8. The plan need not allocate the work equally over the respective periods, but should allocate material increments throughout such periods commensurate with the work to be undertaken. No later than April 1 of each subsequent year, the utility shall submit to the Commission a report that includes any updates to the plan, a schedule for the next calendar year, the expenditures made for the prior calendar year and cumulatively, and the number of full-time equivalent jobs created for the prior calendar year and cumulatively. If the utility is materially deficient in satisfying a schedule or staffing plan, then the report must also include a corrective action plan to address the deficiency. The fact that the plan, implementation of the plan, or a schedule changes shall not imply the imprudence or unreasonableness of the infrastructure investment program, plan, or schedule. Further, no later than 45 days following the last day of the first, second, and third quarters of each year of the plan, a participating utility shall submit to the Commission a verified quarterly report for the prior quarter that includes (i) the total number of full-time equivalent jobs created during the prior quarter, (ii) the total number of employees as of the last day of the prior quarter, (iii) the total number of full-time equivalent hours in each job classification or job title, (iv) the total number of incremental employees and contractors in support of the investments undertaken pursuant to this subsection (b) for the prior quarter, and (v) any other information that the Commission may require by rule.

With respect to the participating utility's peak job commitment, if, after considering the utility's corrective action plan and compliance thereunder, the Commission enters an order finding, after notice and hearing, that a participating utility did not satisfy its peak job commitment described in this subsection (b) for reasons that are reasonably within its control, then the Commission shall also determine, after consideration of the evidence, including, but not limited to, evidence submitted by the Department of Commerce and Economic Opportunity and the utility, the deficiency in the number of full-time equivalent jobs during the peak program year due to such failure. The Commission shall notify the Department of any proceeding that is initiated pursuant to this paragraph. For each full-time equivalent job deficiency during the peak program year that the Commission finds as set forth in this paragraph, the participating utility shall, within 30 days after the entry of the Commission's order, pay $6,000 to a fund for training grants administered under Section 605-800 of the Department of Commerce and Economic Opportunity Law, which shall not be a recoverable expense.

With respect to the participating utility's investment amount commitments, if, after considering the utility's corrective action plan and compliance thereunder, the Commission enters an order finding, after notice and hearing, that a participating utility is not satisfying its investment amount commitments described in this subsection (b), then the utility shall no longer be eligible to annually update the performance-based formula rate tariff pursuant to subsection (d) of this Section. In such event, the then current rates shall remain in effect until such time as new rates are set pursuant to Article IX of this Act, subject to retroactive adjustment, with interest, to reconcile rates charged with actual costs.

If the Commission finds that a participating utility is no longer eligible to update the performance-based formula rate tariff pursuant to subsection (d) of this Section, or the performance-based formula rate is otherwise terminated, then the participating utility's voluntary commitments and obligations under this subsection (b) shall immediately terminate, except for the utility's obligation to pay an amount already owed to the fund for training grants pursuant to a Commission order.

In meeting the obligations of this subsection (b), to the extent feasible and consistent with State and federal law, the investments under the infrastructure investment program should provide employment opportunities for all segments of the population and workforce, including minority-owned and female-owned business enterprises, and shall not, consistent with State and federal law, discriminate based on race or socioeconomic status.

(b-5) Nothing in this Section shall prohibit the Commission from investigating the prudence and reasonableness of the expenditures made under the infrastructure investment program during the annual review required by subsection (d) of this Section and shall, as part of such investigation, determine whether the utility's actual costs under the program are prudent and reasonable. The fact that a participating utility invests more than the minimum amounts specified in subsection (b) of this Section or its plan shall not imply imprudence or unreasonableness.

If the participating utility finds that it is implementing its plan for satisfying the infrastructure investment program commitments described in subsection (b) of this Section at a cost below the estimated amounts specified in subsection (b) of this Section, then the utility may file a petition with the Commission requesting that it be permitted to satisfy its commitments by spending less than the estimated amounts specified in subsection (b) of this Section. The Commission shall, after notice and hearing, enter its order approving, or approving as modified, or denying each such petition within 150 days after the filing of the petition.

In no event, absent General Assembly approval, shall the capital investment costs incurred by a participating utility other than a combination utility in satisfying its infrastructure investment program commitments described in subsection (b) of this Section exceed $3,000,000,000 or, for a participating utility that is a combination utility, $720,000,000. If the participating utility's updated cost estimates for satisfying its infrastructure investment program commitments described in subsection (b) of this Section exceed the limitation imposed by this subsection (b-5), then it shall submit a report to the Commission that identifies the increased costs and explains the reason or reasons for the increased costs no later than the year in which the utility estimates it will exceed the limitation. The Commission shall review the report and shall, within 90 days after the participating utility files the report, report to the General Assembly its findings regarding the participating utility's report. If the General Assembly does not amend the limitation imposed by this subsection (b-5), then the utility may modify its plan so as not to exceed the limitation imposed by this subsection (b-5) and may propose corresponding changes to the metrics established pursuant to subparagraphs (5) through (8) of subsection (f) of this Section, and the Commission may modify the metrics and incremental savings goals established pursuant to subsection (f) of this Section accordingly.

(b-10) All participating utilities shall make contributions for an energy low-income and support program in accordance with this subsection. Beginning no later than 180 days after a participating utility files a performance-based formula rate tariff pursuant to subsection (c) of this Section, or beginning no later than January 1, 2012 if such utility files such performance-based formula rate tariff within 14 days of December 30, 2011 (the effective date of Public Act 97-646), and without obtaining any approvals from the Commission or any other agency other than as set forth in this Section, regardless of whether any such approval would otherwise be required, a participating utility other than a combination utility shall pay $10,000,000 per year for 5 years and a participating utility that is a combination utility shall pay $1,000,000 per year for 10 years to the energy low-income and support program, which is intended to fund customer assistance programs with the primary purpose being avoidance of imminent disconnection. Such programs may include:

(1) a residential hardship program that may partner with community-based organizations, including senior citizen organizations, and provides grants to low-income residential customers, including low-income senior citizens, who demonstrate a hardship;

(2) a program that provides grants and other bill payment concessions to veterans with disabilities who

demonstrate a hardship and members of the armed services or reserve forces of the United States or members of the Illinois National Guard who are on active duty pursuant to an executive order of the President of the United States, an act of the Congress of the United States, or an order of the Governor and who demonstrate a hardship;

(3) a budget assistance program that provides tools and education to low-income senior citizens to assist them with obtaining information regarding energy usage and effective means of managing energy costs;

(4) a non-residential special hardship program that provides grants to non-residential customers such as small businesses and non-profit organizations that demonstrate a hardship, including those providing services to senior citizen and low-income customers; and

(5) a performance-based assistance program that provides grants to encourage residential customers to make on-time payments by matching a portion of the customer's payments or providing credits towards arrearages.

The payments made by a participating utility pursuant to this subsection (b-10) shall not be a recoverable expense. A participating utility may elect to fund either new or existing customer assistance programs, including, but not limited to, those that are administered by the utility.

Programs that use funds that are provided by a participating utility to reduce utility bills may be implemented through tariffs that are filed with and reviewed by the Commission. If a utility elects to file tariffs with the Commission to implement all or a portion of the programs, those tariffs shall, regardless of the date actually filed, be deemed accepted and approved, and shall become effective on December 30, 2011 (the effective date of Public Act 97-646). The participating utilities whose customers benefit from the funds that are disbursed as contemplated in this Section shall file annual reports documenting the disbursement of those funds with the Commission. The Commission has the authority to audit disbursement of the funds to ensure they were disbursed consistently with this Section.

If the Commission finds that a participating utility is no longer eligible to update the performance-based formula rate tariff pursuant to subsection (d) of this Section, or the performance-based formula rate is otherwise terminated, then the participating utility's voluntary commitments and obligations under this subsection (b-10) shall immediately terminate.

(b-15) Beginning in 2022, without obtaining any approvals from the Commission or any other agency, regardless of whether any such approval would otherwise be required, a participating utility that is a combination utility shall pay $1,000,000 per year for 10 years to the energy low-income and support program, which is intended to fund customer assistance programs with the primary purpose of avoidance of imminent disconnection and reconnecting customers who have been disconnected for nonpayment. Such programs may include those described in paragraphs (1) through (5) of subsection (b-10) of this Section.

The payments made by a participating utility pursuant to this subsection (b-15) is not a recoverable expense. A participating utility may elect to fund either new or existing customer assistance programs, including, but not limited to, those that are administered by the utility.

Programs that use funds that are provided by a participating utility to reduce utility bills may be implemented through tariffs that are filed with and reviewed by the Commission. If a utility elects to file tariffs with the Commission to implement all or a portion of the programs, those tariffs shall, regardless of the date actually filed, be deemed accepted and approved, and shall become effective on the first business day after they are filed. The participating utilities whose customers benefit from the funds that are disbursed as contemplated in this subsection (b-15) shall file annual reports documenting the disbursement of those funds with the Commission. The Commission has the authority to audit disbursement of the funds to ensure they were disbursed consistently with this subsection (b-15).

If the Commission finds that a participating utility is no longer eligible to update the performance-based formula rate tariff pursuant to subsection (d) of this Section, or the

<u>performance-based formula rate is otherwise terminated, then the participating utility's voluntary commitments and obligations under this subsection (b-15) shall immediately terminate.</u>

(c) A participating utility may elect to recover its delivery services costs through a performance-based formula rate approved by the Commission, which shall specify the cost components that form the basis of the rate charged to customers with sufficient specificity to operate in a standardized manner and be updated annually with transparent information that reflects the utility's actual costs to be recovered during the applicable rate year, which is the period beginning with the first billing day of January and extending through the last billing day of the following December. In the event the utility recovers a portion of its costs through automatic adjustment clause tariffs on October 26, 2011 (the effective date of Public Act 97-616), the utility may elect to continue to recover these costs through such tariffs, but then these costs shall not be recovered through the performance-based formula rate. In the event the participating utility, prior to December 30, 2011 (the effective date of Public Act 97-646), filed electric delivery services tariffs with the Commission pursuant to Section 9-201 of this Act that are related to the recovery of its electric delivery services costs that are still pending on December 30, 2011 (the effective date of Public Act 97-646), the participating utility shall, at the time it files its performance-based formula rate tariff with the Commission, also file a notice of withdrawal with the Commission to withdraw the electric delivery services tariffs previously filed pursuant to Section 9-201 of this Act. Upon receipt of such notice, the Commission shall dismiss with prejudice any docket that had been initiated to investigate the electric delivery services tariffs filed pursuant to Section 9-201 of this Act, and such tariffs and the record related thereto shall not be the subject of any further hearing, investigation, or proceeding of any kind related to rates for electric delivery services.

The performance-based formula rate shall be implemented through a tariff filed with the Commission consistent with the provisions of this subsection (c) that shall be applicable to all delivery services customers. The Commission shall initiate and conduct an investigation of the tariff in a manner consistent with the provisions of this subsection (c) and the provisions of Article IX of this Act to the extent they do not conflict with this subsection (c). Except in the case where the Commission finds, after notice and hearing, that a participating utility is not satisfying its investment amount commitments under subsection (b) of this Section, the performance-based formula rate shall remain in effect at the discretion of the utility. The performance-based formula rate approved by the Commission shall do the following:

(1) Provide for the recovery of the utility's actual

costs of delivery services that are prudently incurred and reasonable in amount consistent with Commission practice and law. The sole fact that a cost differs from that incurred in a prior calendar year or that an investment is different from that made in a prior calendar year shall not imply the imprudence or unreasonableness of that cost or investment.

(2) Reflect the utility's actual year-end capital structure for the applicable calendar year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law. To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, a participating electric utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

(3) Include a cost of equity, which in all rate years for a participating utility that is not a combination utility, and in each rate year commencing before December 1, 2019 for a participating utility that is a combination utility, shall be calculated as the sum of the following:

(A) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and

(B) 580 basis points.

For a participating utility that is a combination utility, for each rate year commencing after November 30, 2019, the cost of equity shall be calculated as the sum of the following: (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and (ii) 680 basis points; however, if the cost of equity as calculated under this paragraph (3) for each rate year commencing after November 30, 2019, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State is greater than the national average cost of equity for the rate year by 50 basis points or more, then the Illinois Commerce Commission shall include a cost of equity at a rate equal to the national average cost of equity as calculated under this paragraph (3) plus 50 basis points. For purposes of this paragraph (3), the national average cost of equity for a rate year shall be the simple average of the cost of equity approved in each order of a state regulatory commission, other than the Commission, issued during that rate year that is applicable to retail electric service provided by an investor-owned public utility company operating in the United States. No order shall be excluded from the national average cost of equity calculated under this paragraph (3) on the grounds that it is subject to rehearing or appeal. In the hearing during the first rate year commencing after November 30, 2019, the Commission shall set the cost of equity using the method applicable to rate years commencing prior to December 1, 2019. In the hearings in rate years subsequent to such first rate year, the Commission shall set the cost of equity using the method applicable to rate years commencing after November 30, 2019, including the reconciliation of the first rate year commencing after November 30, 2019. If, for any rate year, there are fewer than 15 applicable orders of state regulatory commissions with which to compute the average cost of equity, the Commission shall include in the calculation of the national average the number of state regulatory orders from the prior year or years necessary to reach a total of 15, beginning with the most recently issued and proceeding in reverse chronological order.

At such time as the Board of Governors of the Federal Reserve System ceases to include the monthly average yields of 30-year U.S. Treasury bonds in its weekly H.15 Statistical Release or successor publication, the monthly average yields of the U.S. Treasury bonds then having the longest duration published by the Board of Governors in its weekly H.15 Statistical Release or successor publication shall instead be used for purposes of this paragraph (3).

(4) Permit and set forth protocols, subject to a determination of prudence and reasonableness consistent with Commission practice and law, for the following:

(A) recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance. Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the performance-based formula rate;

(B) recovery of pension and other post-employment benefits expense, provided that such costs are supported by an actuarial study;

(C) recovery of severance costs, provided that if the amount is over $3,700,000 for a participating utility that is a combination utility or $10,000,000 for a participating utility that serves more than 3 million retail customers, then the full amount shall be amortized consistent with subparagraph (F) of this paragraph (4);

(D) investment return at a rate equal to the utility's weighted average cost of long-term debt, on the pension assets as, and in the amount, reported in Account 186 (or in such other Account or Accounts as such asset may subsequently be recorded) of the utility's most recently filed FERC Form 1, net of deferred tax benefits;

(E) recovery of the expenses related to the Commission proceeding under this subsection (c) to approve this performance-based formula rate and initial rates or to subsequent proceedings related to the formula, provided that the recovery shall be amortized over a 3-year period; recovery of expenses related to the annual Commission proceedings under subsection (d) of this Section to review the inputs to the performance-based formula rate shall be expensed and recovered through the performance-based formula rate;

(F) amortization over a 5-year period of the full amount of each charge or credit that exceeds $3,700,000 for a participating utility that is a combination utility or $10,000,000 for a participating utility that serves more than 3 million retail customers in the applicable calendar year and that relates to a workforce reduction program's severance costs, changes in accounting rules, changes in law, compliance with any Commission-initiated audit, or a single storm or other similar expense, provided that any unamortized balance shall be reflected in rate base. For purposes of this subparagraph (F), changes in law includes any enactment, repeal, or amendment in a law, ordinance, rule, regulation, interpretation, permit, license, consent, or order, including those relating to taxes, accounting, or to environmental matters, or in the interpretation or application thereof by any governmental authority occurring after October 26, 2011 (the effective date of Public Act 97-616);

(G) recovery of existing regulatory assets over the periods previously authorized by the Commission;

(H) historical weather normalized billing determinants; and

(I) allocation methods for common costs.

(5) Provide that if the participating utility's earned rate of return on common equity related to the provision of delivery services for the prior rate year (calculated using costs and capital structure approved by the Commission as provided in subparagraph (2) of this subsection (c), consistent with this Section, in accordance with Commission rules and orders, including, but not limited to, adjustments for goodwill, and after any Commission-ordered disallowances and taxes) is more than 50 basis points higher than the rate of return on common equity calculated pursuant to paragraph (3) of this subsection (c) (after

adjusting for any penalties to the rate of return on common equity applied pursuant to the performance metrics provision of subsection (f), (f-5), or (f-10) of this Section, as applicable), then the participating utility shall apply a credit through the performance-based formula rate that reflects an amount equal to the value of that portion of the earned rate of return on common equity that is more than 50 basis points higher than the rate of return on common equity calculated pursuant to paragraph (3) of this subsection (c) (after adjusting for any penalties to the rate of return on common equity applied pursuant to the performance metrics provision of subsection (f), (f-5), or (f-10) of this Section, as applicable) for the prior rate year, adjusted for taxes. If the participating utility's earned rate of return on common equity related to the provision of delivery services for the prior rate year (calculated using costs and capital structure approved by the Commission as provided in subparagraph (2) of this subsection (c), consistent with this Section, in accordance with Commission rules and orders, including, but not limited to, adjustments for goodwill, and after any Commission-ordered disallowances and taxes) is more than 50 basis points less than the return on common equity calculated pursuant to paragraph (3) of this subsection (c) (after adjusting for any penalties to the rate of return on common equity applied pursuant to the performance metrics provision of subsection (f)<u>, (f-5), or (f-10)</u> of this Section<u>, as applicable</u>), then the participating utility shall apply a charge through the performance-based formula rate that reflects an amount equal to the value of that portion of the earned rate of return on common equity that is more than 50 basis points less than the rate of return on common equity calculated pursuant to paragraph (3) of this subsection (c) (after adjusting for any penalties to the rate of return on common equity applied pursuant to the performance metrics provision of subsection (f)<u>, (f-5), or (f-10)</u> of this Section<u>, as applicable</u>) for the prior rate year, adjusted for taxes.

(6) Provide for an annual reconciliation, as described in subsection (d) of this Section, with interest, of the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its performance-based formula rate tariff pursuant to subsection (c) of this Section, with what the revenue requirement would have been had the actual cost information for the applicable calendar year been available at the filing date.

The utility shall file, together with its tariff, final data based on its most recently filed FERC Form 1, plus projected plant additions and correspondingly updated depreciation reserve and expense for the calendar year in which the tariff and data are filed, that shall populate the performance-based formula rate and set the initial delivery services rates under the formula. For purposes of this Section, "FERC Form 1" means the Annual Report of Major Electric Utilities, Licensees and Others that electric utilities are required to file with the Federal Energy Regulatory Commission under the Federal Power Act, Sections 3, 4(a), 304 and 209, modified as necessary to be consistent with 83 Ill. Admin. Code Part 415 as of May 1, 2011. Nothing in this Section is intended to allow costs that are not otherwise recoverable to be recoverable by virtue of inclusion in FERC Form 1.

After the utility files its proposed performance-based formula rate structure and protocols and initial rates, the Commission shall initiate a docket to review the filing. The Commission shall enter an order approving, or approving as modified, the performance-based formula rate, including the initial rates, as just and reasonable within 270 days after the date on which the tariff was filed, or, if the tariff is filed within 14 days after October 26, 2011 (the effective date of Public Act 97-616), then by May 31, 2012. Such review shall be based on the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, the Commission applies in a hearing to review a filing for a general increase in rates under Article IX of this Act. The initial rates shall take effect within 30 days after the Commission's order approving the performance-based formula rate tariff.

Until such time as the Commission approves a different rate design and cost allocation pursuant to subsection (e) of this Section, rate design and cost allocation across customer classes shall be consistent with the Commission's most recent order regarding the participating utility's request for a general increase in its delivery services rates.

Subsequent changes to the performance-based formula rate structure or protocols shall be made as set forth in Section 9-201 of this Act, but nothing in this subsection (c) is intended to limit the Commission's authority under Article IX and other provisions of this Act to initiate an investigation of a participating utility's performance-based formula rate tariff, provided that any such changes shall be consistent with paragraphs (1) through (6) of this subsection (c). Any change ordered by the Commission shall be made at the same time new rates take effect following the Commission's next order pursuant to subsection (d) of this Section, provided that the new rates take effect no less than 30 days after the date on which the Commission issues an order adopting the change.

A participating utility that files a tariff pursuant to this subsection (c) must submit a one-time $200,000 filing fee at the time the Chief Clerk of the Commission accepts the filing, which shall be a recoverable expense.

In the event the performance-based formula rate is terminated, the then current rates shall remain in effect until such time as new rates are set pursuant to Article IX of this

Act, subject to retroactive rate adjustment, with interest, to reconcile rates charged with actual costs. At such time that the performance-based formula rate is terminated, the participating utility's voluntary commitments and obligations under subsection (b) of this Section shall immediately terminate, except for the utility's obligation to pay an amount already owed to the fund for training grants pursuant to a Commission order issued under subsection (b) of this Section.

(d) Subsequent to the Commission's issuance of an order approving the utility's performance-based formula rate structure and protocols, and initial rates under subsection (c) of this Section, the utility shall file, on or before May 1 of each year, with the Chief Clerk of the Commission its updated cost inputs to the performance-based formula rate for the applicable rate year and the corresponding new charges. Each such filing shall conform to the following requirements and include the following information:

(1) The inputs to the performance-based formula rate for the applicable rate year shall be based on final historical data reflected in the utility's most recently filed annual FERC Form 1 plus projected plant additions and correspondingly updated depreciation reserve and expense for the calendar year in which the inputs are filed. The filing shall also include a reconciliation of the revenue requirement that was in effect for the prior rate year (as set by the cost inputs for the prior rate year) with the

actual revenue requirement for the prior rate year (determined using a year-end rate base) that uses amounts reflected in the applicable FERC Form 1 that reports the actual costs for the prior rate year. Any over-collection or under-collection indicated by such reconciliation shall be reflected as a credit against, or recovered as an additional charge to, respectively, with interest calculated at a rate equal to the utility's weighted average cost of capital approved by the Commission for the prior rate year, the charges for the applicable rate year. Provided, however, that the first such reconciliation shall be for the calendar year in which the utility files its performance-based formula rate tariff pursuant to subsection (c) of this Section and shall reconcile (i) the revenue requirement or requirements established by the rate order or orders in effect from time to time during such calendar year (weighted, as applicable) with (ii) the revenue requirement determined using a year-end rate base for that calendar year calculated pursuant to the performance-based formula rate using (A) actual costs for that year as reflected in the applicable FERC Form 1, and (B) for the first such reconciliation only, the cost of equity, which shall be calculated as the sum of 590 basis points plus the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve

System in its weekly H.15 Statistical Release or successor publication. The first such reconciliation is not intended to provide for the recovery of costs previously excluded from rates based on a prior Commission order finding of imprudence or unreasonableness. Each reconciliation shall be certified by the participating utility in the same manner that FERC Form 1 is certified. The filing shall also include the charge or credit, if any, resulting from the calculation required by paragraph (6) of subsection (c) of this Section.

Notwithstanding anything that may be to the contrary, the intent of the reconciliation is to ultimately reconcile the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its performance-based formula rate tariff pursuant to subsection (c) of this Section, with what the revenue requirement determined using a year-end rate base for the applicable calendar year would have been had the actual cost information for the applicable calendar year been available at the filing date.

(2) The new charges shall take effect beginning on the first billing day of the following January billing period and remain in effect through the last billing day of the next December billing period regardless of whether the Commission enters upon a hearing pursuant to this subsection (d).

(3) The filing shall include relevant and necessary data and documentation for the applicable rate year that is consistent with the Commission's rules applicable to a filing for a general increase in rates or any rules adopted by the Commission to implement this Section. Normalization adjustments shall not be required. Notwithstanding any other provision of this Section or Act or any rule or other requirement adopted by the Commission, a participating utility that is a combination utility with more than one rate zone shall not be required to file a separate set of such data and documentation for each rate zone and may combine such data and documentation into a single set of schedules.

Within 45 days after the utility files its annual update of cost inputs to the performance-based formula rate, the Commission shall have the authority, either upon complaint or its own initiative, but with reasonable notice, to enter upon a hearing concerning the prudence and reasonableness of the costs incurred by the utility to be recovered during the applicable rate year that are reflected in the inputs to the performance-based formula rate derived from the utility's FERC Form 1. During the course of the hearing, each objection shall be stated with particularity and evidence provided in support thereof, after which the utility shall have the opportunity to rebut the evidence. Discovery shall be allowed consistent with the Commission's Rules of Practice, which Rules shall be enforced by the Commission or the assigned administrative law judge. The Commission shall apply the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, in the hearing as it would apply in a hearing to review a filing for a general increase in rates under Article IX of this Act. The Commission shall not, however, have the authority in a proceeding under this subsection (d) to consider or order any changes to the structure or protocols of the performance-based formula rate approved pursuant to subsection (c) of this Section. In a proceeding under this subsection (d), the Commission shall enter its order no later than the earlier of 240 days after the utility's filing of its annual update of cost inputs to the performance-based formula rate or December 31. The Commission's determinations of the prudence and reasonableness of the costs incurred for the applicable calendar year shall be final upon entry of the Commission's order and shall not be subject to reopening, reexamination, or collateral attack in any other Commission proceeding, case, docket, order, rule or regulation, provided, however, that nothing in this subsection (d) shall prohibit a party from petitioning the Commission to rehear or appeal to the courts the order pursuant to the provisions of this Act.

In the event the Commission does not, either upon complaint or its own initiative, enter upon a hearing within 45 days after the utility files the annual update of cost inputs to its performance-based formula rate, then the costs incurred for the applicable calendar year shall be deemed prudent and reasonable, and the filed charges shall not be subject to reopening, reexamination, or collateral attack in any other proceeding, case, docket, order, rule, or regulation.

A participating utility's first filing of the updated cost inputs, and any Commission investigation of such inputs pursuant to this subsection (d) shall proceed notwithstanding the fact that the Commission's investigation under subsection (c) of this Section is still pending and notwithstanding any other law, order, rule, or Commission practice to the contrary.

(e) Nothing in subsections (c) or (d) of this Section shall prohibit the Commission from investigating, or a participating utility from filing, revenue-neutral tariff changes related to rate design of a performance-based formula rate that has been placed into effect for the utility. Following approval of a participating utility's performance-based formula rate tariff pursuant to subsection (c) of this Section, the utility shall make a filing with the Commission within one year after the effective date of the performance-based formula rate tariff that proposes changes to the tariff to incorporate the findings of any final rate design orders of the Commission applicable to the participating utility and entered subsequent to the Commission's approval of the tariff. The Commission shall, after notice and hearing, enter its order approving, or approving with modification, the proposed changes to the performance-based formula rate tariff within 240 days after the utility's filing. Following such approval, the utility shall make a filing with the Commission during each subsequent 3-year period that either proposes revenue-neutral tariff changes or re-files the existing tariffs without change, which shall present the Commission with an opportunity to suspend the tariffs and consider revenue-neutral tariff changes related to rate design.

(f) Within 30 days after the filing of a tariff pursuant to subsection (c) of this Section, each participating utility shall develop and file with the Commission multi-year metrics designed to achieve, ratably (i.e., in equal segments) over a 10-year period, improvement over baseline performance values as follows:

(1) Twenty percent improvement in the System Average Interruption Frequency Index, using a baseline of the average of the data from 2001 through 2010.

(2) Fifteen percent improvement in the system Customer Average Interruption Duration Index, using a baseline of the average of the data from 2001 through 2010.

(3) For a participating utility other than a combination utility, 20% improvement in the System Average Interruption Frequency Index for its Southern Region, using a baseline of the average of the data from 2001 through 2010. For purposes of this paragraph (3), Southern Region shall have the meaning set forth in the

participating utility's most recent report filed pursuant to Section 16-125 of this Act.

(3.5) For a participating utility other than a combination utility, 20% improvement in the System Average Interruption Frequency Index for its Northeastern Region, using a baseline of the average of the data from 2001 through 2010. For purposes of this paragraph (3.5), Northeastern Region shall have the meaning set forth in the participating utility's most recent report filed pursuant to Section 16-125 of this Act.

(4) Seventy-five percent improvement in the total number of customers who exceed the service reliability targets as set forth in subparagraphs (A) through (C) of paragraph (4) of subsection (b) of 83 Ill. Admin. Code Part 411.140 as of May 1, 2011, using 2010 as the baseline year.

(5) Reduction in issuance of estimated electric bills: 90% improvement for a participating utility other than a combination utility, and 56% improvement for a participating utility that is a combination utility, using a baseline of the average number of estimated bills for the years 2008 through 2010.

(6) Consumption on inactive meters: 90% improvement for a participating utility other than a combination utility, and 56% improvement for a participating utility that is a combination utility, using a baseline of the average unbilled kilowatthours for the years 2009 and 2010.

(7) Unaccounted for energy: 50% improvement for a participating utility other than a combination utility using a baseline of the non-technical line loss unaccounted for energy kilowatthours for the year 2009.

(8) Uncollectible expense: reduce uncollectible expense by at least $30,000,000 for a participating utility other than a combination utility and by at least $3,500,000 for a participating utility that is a combination utility, using a baseline of the average uncollectible expense for the years 2008 through 2010.

(9) Opportunities for minority-owned and female-owned business enterprises: design a performance metric regarding the creation of opportunities for minority-owned and female-owned business enterprises consistent with State and federal law using a base performance value of the percentage of the participating utility's capital expenditures that were paid to minority-owned and female-owned business enterprises in 2010.

The definitions set forth in 83 Ill. Admin. Code Part 411.20 as of May 1, 2011 shall be used for purposes of calculating performance under paragraphs (1) through (3.5) of this subsection (f), provided, however, that the participating utility may exclude up to 9 extreme weather event days from such calculation for each year, and provided further that the participating utility shall exclude 9 extreme weather event days when calculating each year of the baseline period to the extent that there are 9 such days in a given year of the baseline period. For purposes of this Section, an extreme weather event day is a 24-hour calendar day (beginning at 12:00 a.m. and ending at 11:59 p.m.) during which any weather event (e.g., storm, tornado) caused interruptions for 10,000 or more of the participating utility's customers for 3 hours or more. If there are more than 9 extreme weather event days in a year, then the utility may choose no more than 9 extreme weather event days to exclude, provided that the same extreme weather event days are excluded from each of the calculations performed under paragraphs (1) through (3.5) of this subsection (f).

The metrics shall include incremental performance goals for each year of the 10-year period, which shall be designed to demonstrate that the utility is on track to achieve the performance goal in each category at the end of the 10-year period. The utility shall elect when the 10-year period shall commence for the metrics set forth in subparagraphs (1) through (4) and (9) of this subsection (f), provided that it begins no later than 14 months following the date on which the utility begins investing pursuant to subsection (b) of this Section, and when the 10-year period shall commence for the metrics set forth in subparagraphs (5) through (8) of this subsection (f), provided that it begins no later than 14 months following the date on which the Commission enters its order approving the utility's Advanced Metering Infrastructure Deployment Plan pursuant to subsection (c) of Section 16-108.6 of this Act.

The metrics and performance goals set forth in subparagraphs (5) through (8) of this subsection (f) are based on the assumptions that the participating utility may fully implement the technology described in subsection (b) of this Section, including utilizing the full functionality of such technology and that there is no requirement for personal on-site notification. If the utility is unable to meet the metrics and performance goals set forth in subparagraphs (5) through (8) of this subsection (f) for such reasons, and the Commission so finds after notice and hearing, then the utility shall be excused from compliance, but only to the limited extent achievement of the affected metrics and performance goals was hindered by the less than full implementation.

(f-5) The financial penalties applicable to the metrics described in subparagraphs (1) through (8) of subsection (f) of this Section, as applicable, shall be applied through an adjustment to the participating utility's return on equity of no more than a total of 30 basis points in each of the first 3 years, of no more than a total of 34 basis points in each of the 3 years thereafter, and of no more than a total of 38 basis points in each of the 4 years thereafter, as follows:

(1) With respect to each of the incremental annual performance goals established pursuant to paragraph (1) of subsection (f) of this Section,

(A) for each year that a participating utility other than a combination utility does not achieve the annual goal, the participating utility's return on equity shall be reduced as follows: during years 1 through 3, by 5 basis points; during years 4 through 6, by 6 basis points; and during years 7 through 10, by 7 basis points; and

(B) for each year that a participating utility that is a combination utility does not achieve the annual goal, the participating utility's return on equity shall be reduced as follows: during years 1 through 3, by 10 basis points; during years 4 through 6, by 12 basis points; and during years 7 through 10, by 14 basis points.

(2) With respect to each of the incremental annual performance goals established pursuant to paragraph (2) of subsection (f) of this Section, for each year that the participating utility does not achieve each such goal, the participating utility's return on equity shall be reduced as follows: during years 1 through 3, by 5 basis points; during years 4 through 6, by 6 basis points; and during years 7 through 10, by 7 basis points.

(3) With respect to each of the incremental annual performance goals established pursuant to paragraphs (3) and (3.5) of subsection (f) of this Section, for each year that a participating utility other than a combination utility does not achieve both such goals, the participating utility's return on equity shall be reduced as follows:

during years 1 through 3, by 5 basis points; during years 4 through 6, by 6 basis points; and during years 7 through 10, by 7 basis points.

(4) With respect to each of the incremental annual performance goals established pursuant to paragraph (4) of subsection (f) of this Section, for each year that the participating utility does not achieve each such goal, the participating utility's return on equity shall be reduced as follows: during years 1 through 3, by 5 basis points; during years 4 through 6, by 6 basis points; and during years 7 through 10, by 7 basis points.

(5) With respect to each of the incremental annual performance goals established pursuant to subparagraph (5) of subsection (f) of this Section, for each year that the participating utility does not achieve at least 95% of each such goal, the participating utility's return on equity shall be reduced by 5 basis points for each such unachieved goal.

(6) With respect to each of the incremental annual performance goals established pursuant to paragraphs (6), (7), and (8) of subsection (f) of this Section, as applicable, which together measure non-operational customer savings and benefits relating to the implementation of the Advanced Metering Infrastructure Deployment Plan, as defined in Section 16-108.6 of this Act, the performance under each such goal shall be

calculated in terms of the percentage of the goal achieved. The percentage of goal achieved for each of the goals shall be aggregated, and an average percentage value calculated, for each year of the 10-year period. If the utility does not achieve an average percentage value in a given year of at least 95%, the participating utility's return on equity shall be reduced by 5 basis points.

The financial penalties shall be applied as described in this subsection (f-5) for the 12-month period in which the deficiency occurred through a separate tariff mechanism, which shall be filed by the utility together with its metrics. In the event the formula rate tariff established pursuant to subsection (c) of this Section terminates, the utility's obligations under subsection (f) of this Section and this subsection (f-5) shall also terminate, provided, however, that the tariff mechanism established pursuant to subsection (f) of this Section and this subsection (f-5) shall remain in effect until any penalties due and owing at the time of such termination are applied.

The Commission shall, after notice and hearing, enter an order within 120 days after the metrics are filed approving, or approving with modification, a participating utility's tariff or mechanism to satisfy the metrics set forth in subsection (f) of this Section. On June 1 of each subsequent year, each participating utility shall file a report with the Commission that includes, among other things, a description of how the participating utility performed under each metric and an identification of any extraordinary events that adversely impacted the utility's performance. Whenever a participating utility does not satisfy the metrics required pursuant to subsection (f) of this Section, the Commission shall, after notice and hearing, enter an order approving financial penalties in accordance with this subsection (f-5). The Commission-approved financial penalties shall be applied beginning with the next rate year. Nothing in this Section shall authorize the Commission to reduce or otherwise obviate the imposition of financial penalties for failing to achieve one or more of the metrics established pursuant to subparagraph (1) through (4) of subsection (f) of this Section.

(f-10) Each applicable 10-year period previously approved by the Commission pursuant to subsections (f) and (f-5) of this Section for a participating utility that is a combination utility shall be extended for an additional 10-year period that commences immediately after the termination of the previous 10-year period. The performance goals and financial penalties applicable to each year of an additional 10-year period shall be fixed at, and the same as, the performance goals applicable to year 10 that were previously approved by the Commission pursuant to subsections (f) and (f-5) of this Section and the financial penalties applicable to year 10 set forth in subsection (f-5) of this Section. The total amount of financial penalties applicable in any given year shall not exceed 38 basis points. During the additional 10-year period, each participating utility shall continue to file the annual reports required by subsection (f-5) of this Section, and the requirements of subsection (f-5) related to Commission approval of any financial penalties shall continue to apply. The tariff or tariffs approved under subsection (f-5) of this Section for each participating utility that is a combination utility shall remain in effect during the additional 10-year period, and each participating utility that is a combination utility is authorized to submit a compliance filing after the effective date of this amendatory Act of the 101st General Assembly conforming its tariff or tariffs to the provisions of this subsection (f-10). In the event the formula rate tariff established pursuant to subsection (c) of this Section terminates, the utility's obligations under this subsection (f-10) shall also terminate; however, the tariff mechanism established pursuant to subsections (f) and (f-5) of this Section, and extended under this subsection (f-10), shall remain in effect until any penalties due and owing at the time of such termination are applied.

The metrics and performance goals set forth in paragraphs (5) through (8) of subsection (f) of this Section and extended under this subsection (f-10), are based on the assumption that the participating utility may fully implement the technology described in subsection (b) of this Section, including utilizing the full functionality of such technology and that there is no requirement for personal on-site notification. If the utility is unable to meet the metrics and performance goals applicable to paragraphs (5) through (8) of subsection (f) of this Section for such reasons during the additional 10-year period, as those metrics and goals are set by this subsection (f-10), and the Commission so finds after notice and hearing, then the utility shall be excused from compliance, but only to the limited extent achievement of the affected metrics and performance goals was hindered by the less than full implementation.

(g) On or before July 31, 2014, each participating utility shall file a report with the Commission that sets forth the average annual increase in the average amount paid per kilowatthour for residential eligible retail customers, exclusive of the effects of energy efficiency programs, comparing the 12-month period ending May 31, 2012; the 12-month period ending May 31, 2013; and the 12-month period ending May 31, 2014. For a participating utility that is a combination utility with more than one rate zone, the weighted average aggregate increase shall be provided. The report shall be filed together with a statement from an independent auditor attesting to the accuracy of the report. The cost of the independent auditor shall be borne by the participating utility and shall not be a recoverable expense. "The average amount paid per kilowatthour" shall be based on the participating utility's tariffed rates actually in effect and shall not be calculated using any hypothetical rate or adjustments to actual charges (other than as specified for energy efficiency) as an input.

In the event that the average annual increase exceeds 2.5% as calculated pursuant to this subsection (g), then Sections 16-108.5, 16-108.6, 16-108.7, and 16-108.8 of this Act, other than this subsection, shall be inoperative as they relate to the utility and its service area as of the date of the report due to be submitted pursuant to this subsection and the utility shall no longer be eligible to annually update the performance-based formula rate tariff pursuant to subsection (d) of this Section. In such event, the then current rates shall remain in effect until such time as new rates are set pursuant to Article IX of this Act, subject to retroactive adjustment, with interest, to reconcile rates charged with actual costs, and the participating utility's voluntary commitments and obligations under subsection (b) of this Section shall immediately terminate, except for the utility's obligation to pay an amount already owed to the fund for training grants pursuant to a Commission order issued under subsection (b) of this Section.

In the event that the average annual increase is 2.5% or less as calculated pursuant to this subsection (g), then the performance-based formula rate shall remain in effect as set forth in this Section.

For purposes of this Section, the amount per kilowatthour means the total amount paid for electric service expressed on a per kilowatthour basis, and the total amount paid for electric service includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes exclusive of any increases in taxes or new taxes imposed after October 26, 2011 (the effective date of Public Act 97-616). For purposes of this Section, "eligible retail customers" shall have the meaning set forth in Section 16-111.5 of this Act.

The fact that this Section becomes inoperative as set forth in this subsection shall not be construed to mean that the Commission may reexamine or otherwise reopen prudence or reasonableness determinations already made.

(h) By December 31, 2017, the Commission shall prepare and file with the General Assembly a report on the infrastructure program and the performance-based formula rate. The report shall include the change in the average amount per kilowatthour paid by residential customers between June 1, 2011 and May 31, 2017. If the change in the total average rate paid exceeds 2.5% compounded annually, the Commission shall include in the report an analysis that shows the portion of the change due to the delivery services component and the portion of the change due to the supply component of the rate. The report shall include separate sections for each participating utility.

This Section, other than this subsection (h), and Sections ~~16-108.5,~~ 16-108.6, 16-108.7, and 16-108.8 of this Act~~, other than this subsection (h),~~ are inoperative after December 31, 2022 for every participating utility other than a combination

<u>utility</u>, after which time a participating utility <u>other than a combination utility</u> shall no longer be eligible to annually update the performance-based formula rate tariff pursuant to subsection (d) of this Section. At such time, the then current rates shall remain in effect until such time as new rates are set pursuant to Article IX of this Act, subject to retroactive adjustment, with interest, to reconcile rates charged with actual costs.

<u>This Section, other than this subsection (h), and Sections 16-108.6, 16-108.7, and 16-108.8 of this Act are inoperative after December 31, 2032 for every participating utility that is a combination utility, after which time a participating utility that is a combination utility shall no longer be eligible to annually update the performance-based formula rate tariff pursuant to subsection (d) of this Section. At such time, the then current rates shall remain in effect until new rates are set pursuant to Article IX of this Act, subject to retroactive adjustment, with interest, to reconcile rates charged with actual costs.</u>

The fact that this Section becomes inoperative as set forth in this subsection shall not be construed to mean that the Commission may reexamine or otherwise reopen prudence or reasonableness determinations already made.

(i) While a participating utility may use, develop, and maintain broadband systems and the delivery of broadband services, voice-over-internet-protocol services, telecommunications services, and cable and video programming services for use in providing delivery services and Smart Grid functionality or application to its retail customers, including, but not limited to, the installation, implementation and maintenance of Smart Grid electric system upgrades as defined in Section 16-108.6 of this Act, a participating utility is prohibited from offering to its retail customers broadband services or the delivery of broadband services, voice-over-internet-protocol services, telecommunications services, or cable or video programming services, unless they are part of a service directly related to delivery services or Smart Grid functionality or applications as defined in Section 16-108.6 of this Act, and from recovering the costs of such offerings from retail customers.

(j) Nothing in this Section is intended to legislatively overturn the opinion issued in Commonwealth Edison Co. v. Ill. Commerce Comm'n, Nos. 2-08-0959, 2-08-1037, 2-08-1137, 1-08-3008, 1-08-3030, 1-08-3054, 1-08-3313 cons. (Ill. App. Ct. 2d Dist. Sept. 30, 2010). Public Act 97-616 shall not be construed as creating a contract between the General Assembly and the participating utility, and shall not establish a property right in the participating utility.

(k) The changes made in subsections (c) and (d) of this Section by Public Act 98-15 are intended to be a restatement and clarification of existing law, and intended to give binding effect to the provisions of House Resolution 1157 adopted by the House of Representatives of the 97th General Assembly and Senate Resolution 821 adopted by the Senate of the 97th General Assembly that are reflected in paragraph (3) of this subsection. In addition, Public Act 98-15 preempts and supersedes any final Commission orders entered in Docket Nos. 11-0721, 12-0001, 12-0293, and 12-0321 to the extent inconsistent with the amendatory language added to subsections (c) and (d).

(1) No earlier than 5 business days after May 22, 2013 (the effective date of Public Act 98-15), each participating utility shall file any tariff changes necessary to implement the amendatory language set forth in subsections (c) and (d) of this Section by Public Act 98-15 and a revised revenue requirement under the participating utility's performance-based formula rate. The Commission shall enter a final order approving such tariff changes and revised revenue requirement within 21 days after the participating utility's filing.

(2) Notwithstanding anything that may be to the contrary, a participating utility may file a tariff to retroactively recover its previously unrecovered actual costs of delivery service that are no longer subject to recovery through a reconciliation adjustment under subsection (d) of this Section. This retroactive recovery shall include any derivative adjustments resulting from the changes to subsections (c) and (d) of this Section by

Public Act 98-15. Such tariff shall allow the utility to assess, on current customer bills over a period of 12 monthly billing periods, a charge or credit related to those unrecovered costs with interest at the utility's weighted average cost of capital during the period in which those costs were unrecovered. A participating utility may file a tariff that implements a retroactive charge or credit as described in this paragraph for amounts not otherwise included in the tariff filing provided for in paragraph (1) of this subsection (k). The Commission shall enter a final order approving such tariff within 21 days after the participating utility's filing.

(3) The tariff changes described in paragraphs (1) and (2) of this subsection (k) shall relate only to, and be consistent with, the following provisions of Public Act 98-15: paragraph (2) of subsection (c) regarding year-end capital structure, subparagraph (D) of paragraph (4) of subsection (c) regarding pension assets, and subsection (d) regarding the reconciliation components related to year-end rate base and interest calculated at a rate equal to the utility's weighted average cost of capital.

(4) Nothing in this subsection is intended to effect a dismissal of or otherwise affect an appeal from any final Commission orders entered in Docket Nos. 11-0721, 12-0001, 12-0293, and 12-0321 other than to the extent of the amendatory language contained in subsections (c) and (d) of

this Section of Public Act 98-15.

(l) Each participating utility shall be deemed to have been in full compliance with all requirements of subsection (b) of this Section, subsection (c) of this Section, Section 16-108.6 of this Act, and all Commission orders entered pursuant to Sections 16-108.5 and 16-108.6 of this Act, up to and including May 22, 2013 (the effective date of Public Act 98-15). The Commission shall not undertake any investigation of such compliance and no penalty shall be assessed or adverse action taken against a participating utility for noncompliance with Commission orders associated with subsection (b) of this Section, subsection (c) of this Section, and Section 16-108.6 of this Act prior to such date. Each participating utility other than a combination utility shall be permitted, without penalty, a period of 12 months after such effective date to take actions required to ensure its infrastructure investment program is in compliance with subsection (b) of this Section and with Section 16-108.6 of this Act. Provided further, the following subparagraphs shall apply to a participating utility other than a combination utility:

(A) if the Commission has initiated a proceeding pursuant to subsection (e) of Section 16-108.6 of this Act that is pending as of May 22, 2013 (the effective date of Public Act 98-15), then the order entered in such proceeding shall, after notice and hearing, accelerate the commencement of the meter deployment schedule approved in the final Commission order on rehearing entered in Docket No. 12-0298;

(B) if the Commission has entered an order pursuant to subsection (e) of Section 16-108.6 of this Act prior to May 22, 2013 (the effective date of Public Act 98-15) that does not accelerate the commencement of the meter deployment schedule approved in the final Commission order on rehearing entered in Docket No. 12-0298, then the utility shall file with the Commission, within 45 days after such effective date, a plan for accelerating the commencement of the utility's meter deployment schedule approved in the final Commission order on rehearing entered in Docket No. 12-0298; the Commission shall reopen the proceeding in which it entered its order pursuant to subsection (e) of Section 16-108.6 of this Act and shall, after notice and hearing, enter an amendatory order that approves or approves as modified such accelerated plan within 90 days after the utility's filing; or

(C) if the Commission has not initiated a proceeding pursuant to subsection (e) of Section 16-108.6 of this Act prior to May 22, 2013 (the effective date of Public Act 98-15), then the utility shall file with the Commission, within 45 days after such effective date, a plan for accelerating the commencement of the utility's meter deployment schedule approved in the final Commission order on rehearing entered in Docket No. 12-0298 and the

Commission shall, after notice and hearing, approve or approve as modified such plan within 90 days after the utility's filing.

Any schedule for meter deployment approved by the Commission pursuant to this subsection (l) shall take into consideration procurement times for meters and other equipment and operational issues. Nothing in Public Act 98-15 shall shorten or extend the end dates for the 5-year or 10-year periods set forth in subsection (b) of this Section or Section 16-108.6 of this Act. Nothing in this subsection is intended to address whether a participating utility has, or has not, satisfied any or all of the metrics and performance goals established pursuant to subsection (f) of this Section.

(m) The provisions of Public Act 98-15 are severable under Section 1.31 of the Statute on Statutes.

(Source: P.A. 99-143, eff. 7-27-15; 99-642, eff. 7-28-16; 99-906, eff. 6-1-17; 100-840, eff. 8-13-18.)

(220 ILCS 5/16-108.19 new)

Sec. 16-108.19. Electric vehicle charging station infrastructure.

(a) Notwithstanding any other provisions of this Act and without obtaining any approvals from the Commission or any other agency, including, but not limited to, approvals otherwise required under Section 8-406 of this Act, regardless of whether any such approval would otherwise be required, electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State are authorized to, but are not required to, plan for, construct, install, control, own, manage, or operate electric vehicle charging infrastructure, including, but not limited to, electric vehicle charging stations within their service territories. Electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State may construct electric vehicle charging infrastructure on private property or publicly owned property; however, the Commission may not authorize an electric utility under Section 8-509 of this Act to acquire property rights by eminent domain for the construction of any electric vehicle charging station. Electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall be allowed to recover all reasonable and prudent costs associated with investment in the electric vehicle charging infrastructure, including, but not limited to, costs to plan for, construct, install, control, own, manage, or operate under this Section through the applicable provisions of this Article XVI or Article IX of this Act.

(b) Electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State may file with the Commission an electric vehicle charging infrastructure deployment and charging facility rebate plan, the purpose of which shall be to encourage the adoption of electric vehicles in this State, including in the service territory of the electric utilities subject to this Section. The plan filed by an electric utility subject to this Section shall identify a system of publicly accessible electric vehicle charging stations and a schedule of rebates that would be available to: (1) retail customers taking electric service from the electric utility at an address in the electric utility's service territory; and (2) any third party that would construct, own, or operate a publicly accessible electric vehicle charging station as authorized by this Section. The Commission shall review the plan for compliance with the provisions of this Section 16-108.19 and issue an order either approving or modifying the plan within 180 days after the initial filing. If the Commission finds that the plan filed pursuant to this subsection (b) of this Section complies with the requirements of subsections (c) and (d) of this Section, the Commission shall approve the plan and the electric utility shall implement it in accordance with the Commission approval. If the Commission modifies the plan, the electric utility shall notify the Commission in writing within 90 days after service of the Commission's order modifying the plan as to whether the electric utility accepts the Commission's modifications. If the electric utility notifies the Commission in writing that it does not accept the Commission's modifications, the electric utility shall have no further obligations with respect to the plan, including any obligation to implement the plan as modified and may, at its discretion, file a new plan with the Commission in the future. Upon approval by the Commission and acceptance by the electric utility of a plan filed under this subsection (b) of this Section, no further approvals by the Commission other than those approvals set forth in this Section shall be necessary and the electric utility shall implement the approved plan in accordance with the Commission's approval.

(c) A plan filed under subsection (b) of this Section shall include, at a minimum, the following categories of information regarding the proposed deployment of electric vehicle charging stations:

(1) Identification of existing publicly accessible electric vehicle charging station infrastructure installed in the electric utility's service territory.

(2) Sufficient detail to identify the proposed general location and type of electric vehicle charging station infrastructure that could be installed on private or publicly owned land along proposed electric vehicle charging corridors or other public spaces within the electric utility's service territory, including the general identification of any proposed location and type of electric vehicle charging station infrastructure that the electric utility proposes to be part of the third-party request for proposals process set forth in paragraph (3) of this subsection (c);

(3) A proposed request for proposals process to be

managed by the electric utility, which shall request proposals from third parties to compete for utility rebates for the construction, ownership, and operation of the electric vehicle charging stations within the electric utility's service territory. The request for proposals process shall address at least the following information for the proposed electric vehicle charging infrastructure:

(A) requirements for electric vehicle charging station infrastructure owners and operators regarding construction, installation, operation, and maintenance for each proposed general location;

(B) criteria by which the bids will be reviewed and assessed; however, bids shall address the proposed ownership and ongoing operation of the electric vehicle charging station and the bids may be contingent on securing State or federal funds, including any tax incentives, available for electric vehicle charging station development or deployment;

(C) provisions for how rebates will be made available to electric vehicle charging station winning bidders, which shall be designed to encourage participation in the request for proposals process and actual construction, installation, ownership, and operation of the electric vehicle charging station at each proposed location; and

(D) a proposal that provides the electric utility the option to plan for, construct, install, control, own, manage, or operate any electric vehicle charging infrastructure at any location identified for inclusion in the request for proposals, but for which no third-party bid was received or awarded under the criteria identified pursuant to this paragraph (3).

(d) In addition to the information set forth in subsection (c) of this Section, a plan filed under subsection (b) of this Section shall also include the following categories of information:

(1) The proposed rebates offered by the electric utility to customers taking service from the electric utility at an address within its service territory for electric vehicle charging infrastructure or facilities, which should include, but not be limited to, the following information:

(A) identification of available rebates for electric utility residential customers who purchase electric vehicles and install home electric vehicle charging facilities subsequent to the effective date of this amendatory Act of the 101st General Assembly;

(B) identification of available rebates for multi-family residential buildings and non-residential customers that, subsequent to the effective date of this amendatory Act of the 101st General Assembly, install and provide access to electric vehicle charging facilities located in a common area generally available to residents or the public;

(C) identification of available rebates designed to promote the use of electric vehicles serving low-income or moderate-income communities, including, but not limited to, any rebates available to shared electric vehicles, ride share electric vehicles, and public transportation fleets or school districts using electric vehicles; and

(D) the manner and timing of the payment of the proposed rebates; however, the rebates identified pursuant to this paragraph (1) may be paid through a monthly bill credit spread fairly and reasonably across a 12-month period, and provided any customer receiving a rebate must sign up for and remain on a 3-part delivery service rate, if available.

(2) An estimated budget for the electric utility to develop and implement an education and engagement strategy that encourages the adoption of electric vehicles in the electric utility's service territory, including, but not limited to, programs to be delivered to entities that educate and promote the adoption of electric vehicles, including, but not limited to, car dealerships and elementary, middle, and high schools.

(e) An electric utility implementing a plan approved pursuant to subsection (b) of this Section, may update its plan at any time by filing such update with the Commission in the same docket in which the Commission originally approved the plan. Any updated filing made pursuant to this subsection (e) must identify the updates to be implemented and any updates shall be deemed approved as reasonable 45 days after the filing unless the Commission initiates an investigation into the updated actions. Any final order regarding the investigation initiated pursuant to this subsection (e) must be issued within 180 days of the initiating order.

(f) Notwithstanding any other provision of law to the contrary, electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall be permitted to recover all reasonable and prudently incurred costs incurred under this Section, including, but not limited to, any costs incurred to make any location identified pursuant to subsections (b) and (c) of this Section ready for installation and connection of an electric vehicle charging station to the distribution system; the costs incurred to provide the rebates identified pursuant to subsections (b), (c), and (d) of this Section; the costs incurred to undertake the education and engagement activities authorized under this Section; and other costs incurred by the utility to comply with and implement the requirements of this Section, including any amounts that reasonably exceed any estimates provided as part of the plan filed pursuant to subsection (b) of this Section. Electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State are authorized to recover any costs identified in this subsection (f) by way of a tariff or tariffs approved by the Illinois Commerce Commission, consistent with the following provisions:

(1) An electric utility subject to this Section shall be permitted to recover all reasonable and prudently incurred costs incurred to make any location identified pursuant to subsections (b) and (c) of this Section ready for installation and connection of an electric vehicle charging station to the distribution system through its delivery service rates, as authorized by the applicable provisions of Article IX or this Article XVI. For any electric vehicle infrastructure identified in any plan filed pursuant to subsections (b) and (c) of this Section, distribution extension free allowances up to and including $1,500 per kilowatt of electric vehicle charging station expected peak demand shall be deemed reasonable and shall not limit the use of alternate extension provisions demonstrated to be more favorable and approved by the Illinois Commerce Commission.

(2) Beginning on the effective date of this amendatory Act of the 101st General Assembly Act, an electric utility subject to this Section shall have authority to defer up to the full amount of its costs incurred under this Section, other than those costs not being recovered pursuant to

paragraph (1) of this subsection (f) of this Section, as a regulatory asset, to be amortized over a 15-year period. The unamortized balance shall be recognized as of December 31 for a given year. The utility shall also earn a return on the total of the unamortized balance of the regulatory asset authorized under this Section, less any deferred taxes related to the unamortized balance, at an annual rate equal to the utility's weighted average cost of capital that includes, based on a year-end capital structure, the utility's actual cost of debt for the applicable calendar year and a cost of equity, which shall be calculated as the sum of the following: (i) the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication; and (ii) 680 basis points; however, if the cost of equity as calculated under this paragraph (2) is greater than the national average cost of equity for the rate year by 50 basis points or more, then the Illinois Commerce Commission shall include a cost of equity at a rate equal to the national average cost of equity as calculated under this paragraph (2) plus 50 basis points. For purposes of this paragraph (2), the national average cost of equity for a rate year shall be the simple average of the cost of equity approved in each order of a state regulatory commission, other than the

Commission, issued during that rate year that is applicable to retail electric service provided by an investor-owned public utility company operating in the United States. No order shall be excluded from the national average cost of equity calculated under this paragraph (2) on the grounds that it is subject to rehearing or appeal. If, for any rate year, there are fewer than 15 applicable orders of state regulatory commissions with which to compute the average cost of equity, the Commission shall include in the calculation of the national average the number of state regulatory orders from the prior year or years necessary to reach a total of 15, beginning with the most recently issued and proceeding in reverse chronological order. At such time as the Board of Governors of the Federal Reserve System ceases to include the monthly average yields of 30-year U.S. Treasury bonds in its weekly H.15 Statistical Release or successor publication, the monthly average yields of the U.S. Treasury bonds then having the longest duration published by the Board of Governors in its weekly H.15 Statistical Release or successor publication shall instead be used for purposes of this paragraph (2).

(3) When an electric utility subject to this Section creates a regulatory asset under the provisions of this Section, the costs shall be recovered over a period during which customers also receive a benefit, which is in the public interest. Accordingly, it is the intent of the

General Assembly that an electric utility that elects to create a regulatory asset under the provisions of this Section shall recover all of the associated costs, including, but not limited to, its cost of capital as set forth in this Section. After the Commission has approved, as set forth in this Section, the prudence and reasonableness of the costs that comprise the regulatory asset, the electric utility shall be permitted to recover all such costs, and the value and recoverability through rates of the associated regulatory asset shall not be limited, altered, impaired, or reduced. To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities subject to this Section, the utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

(4) Notwithstanding paragraph (1) of this subsection (f), an electric utility subject to this Section may, at its election, recover some or all of the costs it incurs under this Section as part of a filing for a general increase in rates under Article IX of this Act, as part of an annual filing to update a performance-based formula rate under subsection (d) of Section 16-108.5 of this Act or subsection (d) of Section 8-103B, or through an automatic

adjustment clause tariff; provided that nothing in this paragraph (4) of this subsection (f) permits the double recovery of such costs from customers. Such costs shall be allocated across all classes of retail customers in proportion to delivery service revenue revenue requirement attributed to a class. If the electric utility elects to recover the costs it incurs under this Section through an automatic adjustment clause tariff, the utility may file its proposed tariff together with the plan it files under subsection (b) of this Section or at a later time. The proposed tariff shall provide for an annual reconciliation, less any deferred taxes related to the reconciliation, with interest at an annual rate of return equal to the utility's weighted average cost of capital as calculated under paragraph (2) of this subsection (f), including a revenue conversion factor calculated to recover or refund all additional income taxes that may be payable or receivable as a result of that return, of the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its automatic adjustment clause tariff under this subsection (f), with what the revenue requirement would have been had the actual cost information for the applicable calendar year been available at the filing date. The tariff may permit recovery of costs through a single cents per kilowatt-hour charge applicable to each retail class. The Commission shall review the proposed tariff and may make changes to the tariff that are consistent with this Section and with the Commission's authority under Article IX of this Act, subject to notice and hearing, as required. Following notice and hearing, as required, the Commission shall issue an order approving, or approving with modification, such tariff no later than 240 days after the electric utility files its tariff.

(g) Any electric vehicle charging infrastructure, including, but not limited to, an electric vehicle charging station, constructed, installed, controlled, owned, managed, or operated by an electric utility pursuant to this Section shall be treated as jurisdictional distribution plant assets for ratemaking purposes. The investment in, and the costs to construct, install, control, own, manage, or operate electric vehicle charging infrastructure owned by the electric utility shall be fully recovered in delivery service rates. The electric utility shall charge, pursuant to a tariff on file with the Commission, market rates for electricity sold through every such electric vehicle charging station, and all revenue from such sales shall be credited to distribution customers in the applicable ratemaking process.

(h) In addition to the plan authorized in subsection (b), electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in this State shall be permitted to administer programs designed to encourage or incentivize the adoption of electric vehicles by Illinois electric consumers, and such programs shall not be prohibited by the Commission as promotional practices under any rules or policies of the Commission, including, but not limited to, 83 Ill. Adm. Code Part 275.

(220 ILCS 5/16-108.20 new)

Sec. 16-108.20. Electric energy storage.

(a) An electric utility may plan for, construct, install, control, own, manage, or operate energy storage as part of its distribution system when such electric utility has reasonably and prudently assessed and determined that such energy storage will preserve, maintain, or improve stability and reliability of the electric utility's distribution system.

(b) Notwithstanding any other provision of law to the contrary, an electric utility subject to this Section shall be permitted to recover all reasonable and prudently incurred costs incurred under this Section, including, but not limited to, the costs incurred to plan for, construct, control, own, manage, or operate the infrastructure and undertake activities identified in this Section in a reasonable and prudent manner pursuant to Article IX or this Article XVI, as applicable, and for purposes of cost recovery the energy storage facilities shall be treated as distribution assets; provided that: (1) the Commission shall have the authority to determine the reasonableness of the costs of the facilities; and (2) any monetary value of power and energy from the facilities shall be credited against the delivery services revenue requirement. An electric utility subject to this Section shall operate storage for the primary purpose of facilitating stable and reliable delivery service, and any loss incidental to the operation of storage facilities shall also be recoverable to the extent such losses were prudently incurred as a result of the operation of the facility.

(220 ILCS 5/16-128A)

Sec. 16-128A. Certification of installers, maintainers, or repairers.

(a) Within 18 months of the effective date of this amendatory Act of the 97th General Assembly, the Commission shall adopt rules, including emergency rules, establishing certification requirements ensuring that entities installing distributed generation facilities are in compliance with the requirements of subsection (a) of Section 16-128 of this Act.

For purposes of this Section, the phrase "entities installing distributed generation facilities" shall include, but not be limited to, all entities that are exempt from the definition of "alternative retail electric supplier" under item (v) of Section 16-102 of this Act. For purposes of this Section, the phrase "self-installer" means an individual who (i) leases or purchases a cogeneration facility for his or her own personal use and (ii) installs such cogeneration or self-generation facility on his or her own premises without the assistance of any other person.

(b) In addition to any authority granted to the Commission under this Act, the Commission is also authorized to: (1) determine which entities are subject to certification under this Section; (2) impose reasonable certification fees and penalties; (3) adopt disciplinary procedures; (4) investigate any and all activities subject to this Section, including violations thereof; (5) adopt procedures to issue or renew, or to refuse to issue or renew, a certification or to revoke, suspend, place on probation, reprimand, or otherwise discipline a certified entity under this Act or take other enforcement action against an entity subject to this Section; and (6) prescribe forms to be issued for the administration and enforcement of this Section.

(c) No electric utility shall provide a retail customer with net metering service related to interconnection of that customer's distributed generation facility unless the customer provides the electric utility with (i) a certification that the customer installing the distributed generation facility was a self-installer or (ii) evidence that the distributed generation facility was installed by an entity certified under this Section that is also in good standing with the Commission. For purposes of this subsection, a retail customer includes that customer's employees, officers, and agents. An electric utility shall file a tariff or tariffs with the Commission setting forth the documentation, as specified by Commission rule, that a retail customer must provide to an electric utility. The provisions of this subsection (c) shall apply on or after the effective date of the Commission's rules prescribed pursuant to subsection (a) of this Section.

(d) Within 180 days after the effective date of this amendatory Act of the 97th General Assembly, the Commission shall initiate a rulemaking proceeding to establish certification requirements that shall be applicable to persons or entities that install, maintain, or repair electric vehicle charging stations. The notification and certification requirements of this Section shall only be applicable to individuals or entities that perform work on or within an electric vehicle charging station, including, but not limited to, connection of power to an electric vehicle charging station.

~~For the purposes of this Section "electric vehicle charging station" means any facility or equipment that is used to charge a battery or other energy storage device of an electric vehicle.~~

Rules regulating the installation, maintenance, or repair of electric vehicle charging stations, in which the Commission may establish separate requirements based upon the characteristics of electric vehicle charging stations, so long as it is in accordance with the requirements of subsection (a) of Section 16-128 and Section 16-128A of this Act, shall:

(1) establish a certification process for persons or entities that install, maintain, or repair of electric vehicle charging stations;

(2) require persons or entities that install, maintain, or repair electric vehicle stations to be certified to do business and to be bonded in the State;

(3) ensure that persons or entities that install, maintain, or repair electric vehicle charging stations have the requisite knowledge, skills, training, experience, and competence to perform functions in a safe and reliable manner as required under subsection (a) of Section 16-128 of this Act;

(4) impose reasonable certification fees and penalties on persons or entities that install, maintain, or repair of electric vehicle charging stations for noncompliance of the rules adopted under this subsection;

(5) ensure that all persons or entities that install, maintain, or repair electric vehicle charging stations conform to applicable building and electrical codes;

(6) ensure that all electric vehicle charging stations meet recognized industry standards as the Commission deems appropriate, such as the National Electric Code (NEC) and standards developed or created by the Institute of Electrical and Electronics Engineers (IEEE), the Electric Power Research Institute (EPRI), the Detroit Edison Institute (DTE), the Underwriters Laboratory (UL), the

Society of Automotive Engineers (SAE), and the National Institute of Standards and Technology (NIST);

(7) include any additional requirements that the Commission deems reasonable to ensure that persons or entities that install, maintain, or repair electric vehicle charging stations meet adequate training, financial, and competency requirements;

(8) ensure that the obligations required under this Section and subsection (a) of Section 16-128 of this Act are met prior to the interconnection of any electric vehicle charging station;

(9) ensure electric vehicle charging stations installed by a self-installer are not used for any commercial purpose;

(10) establish an inspection procedure for the conversion of electric vehicle charging stations installed by a self-installer if it is determined that the self-installed electric vehicle charging station is being used for commercial purposes;

(11) establish the requirement that all persons or entities that install electric vehicle charging stations shall notify the servicing electric utility in writing of plans to install an electric vehicle charging station and shall notify the servicing electric utility in writing when installation is complete;

(12) ensure that all persons or entities that install,

maintain, or repair electric vehicle charging stations obtain certificates of insurance in sufficient amounts and coverages that the Commission so determines and, if necessary as determined by the Commission, names the affected public utility as an additional insured; and

(13) identify and determine the training or other programs by which persons or entities may obtain the requisite training, skills, or experience necessary to achieve and maintain compliance with the requirements set forth in this subsection and subsection (a) of Section 16-128 to install, maintain, or repair electric vehicle charging stations.

Within 18 months after the effective date of this amendatory Act of the 97th General Assembly, the Commission shall adopt rules, and may, if it deems necessary, adopt emergency rules, for the installation, maintenance, or repair of electric vehicle charging stations.

All retail customers who own, maintain, or repair an electric vehicle charging station shall provide the servicing electric utility (i) a certification that the customer installing the electric vehicle charging station was a self-installer or (ii) evidence that the electric vehicle charging station was installed by an entity certified under this subsection (d) that is also in good standing with the Commission. For purposes of this subsection (d), a retail customer includes that retail customer's employees, officers, and agents. If the electric vehicle charging station was not installed by a self-installer, then the person or entity that plans to install the electric vehicle charging station shall provide notice to the servicing electric utility prior to installation and when installation is complete and provide any other information required by the Commission's rules established under subsection (d) of this Section. An electric utility shall file a tariff or tariffs with the Commission setting forth the documentation, as specified by Commission rule, that a retail customer who owns, uses, operates, or maintains an electric vehicle charging station must provide to an electric utility.

For the purposes of this subsection, an electric vehicle charging station shall constitute a distribution facility or equipment as that term is used in subsection (a) of Section 16-128 of this Act. The phrase "self-installer" means an individual who (i) leases or purchases an electric vehicle charging station for his or her own personal use and (ii) installs an electric vehicle charging station on his or her own premises without the assistance of any other person.

(e) Fees and penalties collected under this Section shall be deposited into the Public Utility Fund and used to fund the Commission's compliance with the obligations imposed by this Section.

(f) The rules established under subsection (d) of this Section shall specify the initial dates for compliance with the rules.

(g) Within 18 months of the effective date of this amendatory Act of the 99th General Assembly, the Commission shall adopt rules, including emergency rules, establishing a process for entities installing a new utility-scale solar project to certify compliance with the requirements of this Section. For purposes of this Section, the phrase "entities installing a new utility-scale solar project" shall include, but is not limited to, any entity installing new photovoltaic projects as such terms are defined in subsection (c) of Section 1-75 of the Illinois Power Agency Act.

The process shall include an option to complete the certification electronically by completing forms on-line. An entity installing a new utility-scale solar project shall be permitted to complete certification after the subject work has been completed. The Commission shall maintain on its website a list of entities installing new utility-scale solar projects measures that have successfully completed the certification process.

(h) In addition to any authority granted to the Commission under this Act, the Commission is also authorized to: (1) determine which entities are subject to certification under subsection (g) of this Section; (2) impose reasonable certification fees and penalties; (3) adopt disciplinary procedures; (4) investigate any and all activities subject to subsection (g) or this subsection (h) of this Section, including violations thereof; (5) adopt procedures to issue or renew, or to refuse to issue or renew, a certification or to revoke, suspend, place on probation, reprimand, or otherwise discipline a certified entity under subsection (g) of this Section or take other enforcement action against an entity subject to subsection (g) or this subsection (h) of this Section; (6) prescribe forms to be issued for the administration and enforcement of subsection (g) and this subsection (h) of this Section; and (7) establish requirements to ensure that entities installing a new photovoltaic project have the requisite knowledge, skills, training, experience, and competence to perform in a safe and reliable manner as required by subsection (a) of Section 16-128 of this Act.

(i) The certification of persons or entities that install, maintain, or repair new photovoltaic projects, distributed generation facilities, and electric vehicle charging stations as set forth in this Section is an exclusive power and function of the State. A home rule unit or other units of local government authority may subject persons or entities that install, maintain, or repair new photovoltaic projects, distributed generation facilities, or electric vehicle charging stations as set forth in this Section to any applicable local licensing, siting, and permitting requirements otherwise permitted under law so long as only Commission-certified persons or entities are authorized to install, maintain, or repair new photovoltaic projects,

distributed generation facilities, or electric vehicle charging stations. This Section is a limitation under subsection (h) of Section 6 of Article VII of the Illinois Constitution on the exercise by home rule units of powers and functions exclusively exercised by the State.
(Source: P.A. 99-906, eff. 6-1-17; 100-16, eff. 6-30-17.)

Section 97. Severability. The provisions of this Act are severable under Section 1.31 of the Statute on Statutes.

Section 99. Effective date. This Act takes effect upon becoming law.

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Statutes amended in order of appearance