



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.

LRB101 20817 JLS 70536 b

1 AN ACT concerning regulation.

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

4 Section 1. Findings.

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

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

24 (2) The changing energy marketplace is having a

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

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

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

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

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

3 (20 ILCS 3855/1-10)

4 Sec. 1-10. Definitions.

5 "Agency" means the Illinois Power Agency.

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

14 "Authority" means the Illinois Finance Authority.

15 "Brownfield site photovoltaic project" means photovoltaics
16 that are:

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

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

24 (A) the United States Environmental Protection

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

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

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

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

12 "Clean coal facility" means an electric generating
13 facility that uses primarily coal as a feedstock and that
14 captures and sequesters carbon dioxide emissions at the
15 following levels: at least 50% of the total carbon dioxide
16 emissions that the facility would otherwise emit if, at the
17 time construction commences, the facility is scheduled to
18 commence operation before 2016, at least 70% of the total
19 carbon dioxide emissions that the facility would otherwise emit
20 if, at the time construction commences, the facility is
21 scheduled to commence operation during 2016 or 2017, and at
22 least 90% of the total carbon dioxide emissions that the
23 facility would otherwise emit if, at the time construction
24 commences, the facility is scheduled to commence operation
25 after 2017. The power block of the clean coal facility shall
26 not exceed allowable emission rates for sulfur dioxide,

1 nitrogen oxides, carbon monoxide, particulates and mercury for
2 a natural gas-fired combined-cycle facility the same size as
3 and in the same location as the clean coal facility at the time
4 the clean coal facility obtains an approved air permit. All
5 coal used by a clean coal facility shall have high volatile
6 bituminous rank and greater than 1.7 pounds of sulfur per
7 million btu content, unless the clean coal facility does not
8 use gasification technology and was operating as a conventional
9 coal-fired electric generating facility on June 1, 2009 (the
10 effective date of Public Act 95-1027).

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

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

14 "Commission" means the Illinois Commerce Commission.

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

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

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

1 Act, or an electric cooperative, as defined in Section
2 3-119 of the Public Utilities Act;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10 "Energy efficiency" means measures that reduce the amount
11 of electricity or natural gas consumed in order to achieve a
12 given end use. "Energy efficiency" includes voltage
13 optimization measures that optimize the voltage at points on
14 the electric distribution voltage system and thereby reduce
15 electricity consumption by electric customers' end use
16 devices. "Energy efficiency" also includes measures that
17 reduce the total Btus of electricity, natural gas, and other
18 fuels needed to meet the end use or uses. For electric
19 utilities that serve less than 3,000,000 retail customers but
20 more than 500,000 retail customers in this State, energy
21 efficiency measures that reduce the total Btus of electricity,
22 natural gas, or other fuels needed to meet the end use or uses,
23 shall include, but are not limited to, measures that educate
24 about, incentivize, encourage, or otherwise support the use of
25 electricity to power, in whole or in part, vehicles, including,
26 but not limited to, cars, trucks, buses, trains, trolleys,

1 boats, on-road or off-road vehicles, or other equipment or
2 methods of transporting goods or people, and such measures
3 shall include, but are not limited to, measures that educate
4 about, incentivize, encourage, or otherwise support the
5 adoption of electric vehicles by retail customers of all
6 customer classes.

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

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

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

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

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

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

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

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

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

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

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

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

19 "Renewable energy resources" includes energy and its
20 associated renewable energy credit or renewable energy credits
21 from wind, solar thermal energy, photovoltaic cells and panels,
22 biodiesel, anaerobic digestion, crops and untreated and
23 unadulterated organic waste biomass, tree waste, and
24 hydropower that does not involve new construction or
25 significant expansion of hydropower dams. For purposes of this
26 Act, landfill gas produced in the State is considered a

1 renewable energy resource. "Renewable energy resources" does
2 not include the incineration or burning of tires, garbage,
3 general household, institutional, and commercial waste,
4 industrial lunchroom or office waste, landscape waste other
5 than tree waste, railroad crossties, utility poles, or
6 construction or demolition debris, other than untreated and
7 unadulterated waste wood.

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

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

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

23 "Service area" has the same definition as found in Section
24 16-102 of the Public Utilities Act.

25 "Sourcing agreement" means (i) in the case of an electric
26 utility, an agreement between the owner of a clean coal

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

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

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

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

5 "Total resource cost test" or "TRC test" means a standard
6 that is met if, for an investment in energy efficiency or
7 demand-response measures, the benefit-cost ratio is greater
8 than one. The benefit-cost ratio is the ratio of the net
9 present value of the total benefits of the program to the net
10 present value of the total costs as calculated over the
11 lifetime of the measures. A total resource cost test compares
12 the sum of avoided electric utility costs, representing the
13 benefits that accrue to the system and the participant in the
14 delivery of those efficiency measures and including avoided
15 costs associated with reduced use of natural gas or other
16 fuels, avoided costs associated with reduced water
17 consumption, and avoided costs associated with reduced
18 operation and maintenance costs, as well as other quantifiable
19 societal benefits, to the sum of all incremental costs of
20 end-use measures that are implemented due to the program
21 (including both utility and participant contributions), plus
22 costs to administer, deliver, and evaluate each demand-side
23 program, to quantify the net savings obtained by substituting
24 the demand-side program for supply resources. In calculating
25 avoided costs of power and energy that an electric utility
26 would otherwise have had to acquire, reasonable estimates shall

1 be included of financial costs likely to be imposed by future
2 regulations and legislation on emissions of greenhouse gases.
3 In discounting future societal costs and benefits for the
4 purpose of calculating net present values, a societal discount
5 rate based on actual, long-term Treasury bond yields should be
6 used. Notwithstanding anything to the contrary, the TRC test
7 shall not include or take into account a calculation of market
8 price suppression effects or demand reduction induced price
9 effects.

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

12 (1) generates electricity using photovoltaic cells;
13 and

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

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

18 (1) generates electricity using wind; and

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

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

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

1 Operator, Inc., or their successors.

2 (Source: P.A. 98-90, eff. 7-15-13; 99-906, eff. 6-1-17.)

3 (20 ILCS 3855/1-75)

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

7 (a) The Planning and Procurement Bureau shall each year,
8 beginning in 2008, develop procurement plans and conduct
9 competitive procurement processes in accordance with the
10 requirements of Section 16-111.5 of the Public Utilities Act
11 for the eligible retail customers of electric utilities that on
12 December 31, 2005 provided electric service to at least 100,000
13 customers in Illinois. Beginning with the delivery year
14 commencing on June 1, 2017, the Planning and Procurement Bureau
15 shall develop plans and processes for the procurement of zero
16 emission credits from zero emission facilities in accordance
17 with the requirements of subsection (d-5) of this Section. The
18 Planning and Procurement Bureau shall also develop procurement
19 plans and conduct competitive procurement processes in
20 accordance with the requirements of Section 16-111.5 of the
21 Public Utilities Act for the eligible retail customers of small
22 multi-jurisdictional electric utilities that (i) on December
23 31, 2005 served less than 100,000 customers in Illinois and
24 (ii) request a procurement plan for their Illinois
25 jurisdictional load. This Section shall not apply to a small

1 multi-jurisdictional utility until such time as a small
2 multi-jurisdictional utility requests the Agency to prepare a
3 procurement plan for their Illinois jurisdictional load. For
4 the purposes of this Section, the term "eligible retail
5 customers" has the same definition as found in Section
6 16-111.5(a) of the Public Utilities Act.

7 Beginning with the plan or plans to be implemented in the
8 2017 delivery year, the Agency shall no longer include the
9 procurement of renewable energy resources in the annual
10 procurement plans required by this subsection (a), except as
11 provided in subsection (q) of Section 16-111.5 of the Public
12 Utilities Act, and shall instead develop a long-term renewable
13 resources procurement plan in accordance with subsection (c) of
14 this Section and Section 16-111.5 of the Public Utilities Act.

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

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

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

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

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

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

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

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

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

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

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

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

26 (D) expertise in wholesale electricity market

1 rules, including those established by the Federal
2 Energy Regulatory Commission and regional transmission
3 organizations;

4 (E) expertise in credit and contract protocols;

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

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

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

25 (A) failure to satisfy qualification criteria;

26 (B) identification of a conflict of interest; or

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

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

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

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

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

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

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

18 (c) Renewable portfolio standard.

19 (1) (A) The Agency shall develop a long-term renewable
20 resources procurement plan that shall include procurement
21 programs and competitive procurement events necessary to
22 meet the goals set forth in this subsection (c). The
23 initial long-term renewable resources procurement plan
24 shall be released for comment no later than 160 days after
25 June 1, 2017 (the effective date of Public Act 99-906). The
26 Agency shall review, and may revise on an expedited basis,

1 the long-term renewable resources procurement plan at
2 least every 2 years, which shall be conducted in
3 conjunction with the procurement plan under Section
4 16-111.5 of the Public Utilities Act to the extent
5 practicable to minimize administrative expense. The
6 long-term renewable resources procurement plans shall be
7 subject to review and approval by the Commission under
8 Section 16-111.5 of the Public Utilities Act.

9 (B) Subject to subparagraph (F) of this paragraph (1),
10 for electric utilities that serve more than 3,000,000
11 retail customers in this State or less than 500,000 retail
12 customers in this State, the long-term renewable resources
13 procurement plan shall include the goals for procurement of
14 renewable energy credits to meet at least the following
15 overall percentages: 13% by the 2017 delivery year;
16 increasing by at least 1.5% each delivery year thereafter
17 to at least 25% by the 2025 delivery year; and continuing
18 at no less than 25% for each delivery year thereafter and
19 for electric utilities that serve less than 3,000,000
20 retail customers but more than 500,000 retail customers in
21 this State, the long-term renewable resources procurement
22 plan shall include the goals for procurement of renewable
23 energy credits to meet at least the following overall
24 percentages: 13% by the 2017 delivery year; increasing by
25 at least 1.5% each delivery year thereafter to at least 25%
26 by the 2025 delivery year, and by at least 1.5% every year

1 thereafter to at least 32.5% by the 2030 delivery year; and
2 continuing at no less than 32.5% for each delivery year
3 thereafter. In the event of a conflict between these goals
4 and the new wind and new photovoltaic procurement
5 requirements described in items (i) through (iii) of
6 subparagraph (C) of this paragraph (1), the long-term plan
7 shall prioritize compliance with the new wind and new
8 photovoltaic procurement requirements described in items
9 (i) through (iii) of subparagraph (C) of this paragraph (1)
10 over the annual percentage targets described in this
11 subparagraph (B).

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

21 For the delivery year beginning June 1, 2018, the
22 procurement plan shall include cost-effective renewable
23 energy resources equal to at least 14.5% of each utility's
24 load for eligible retail customers and 14.5% of the
25 applicable portion of each utility's load for retail
26 customers who are not eligible retail customers, which

1 applicable portion shall equal 75% of the utility's load
2 for retail customers who are not eligible retail customers
3 on February 28, 2017.

4 For the delivery year beginning June 1, 2019, and for
5 each year thereafter, the procurement plans shall include
6 cost-effective renewable energy resources equal to a
7 minimum percentage of each utility's load for all retail
8 customers as follows: for electric utilities that serve
9 more than 3,000,000 retail customers in this State or less
10 than 500,000 retail customers in this State, 16% by June 1,
11 2019; increasing by 1.5% each year thereafter to 25% by
12 June 1, 2025; and 25% by June 1, 2026 and each year
13 thereafter and for electric utilities that serve less than
14 3,000,000 retail customers but more than 500,000 retail
15 customers in this State, 16% by June 1, 2019; increasing by
16 1.5% each year thereafter to 32.5% by June 1, 2030; and
17 32.5% by June 1, 2031 and each year thereafter.

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

25 (C) Of the renewable energy credits procured under this
26 subsection (c), at least 75% shall come from wind and

1 photovoltaic projects. The long-term renewable resources
2 procurement plan described in subparagraph (A) of this
3 paragraph (1) shall include the procurement of renewable
4 energy credits in amounts equal to at least the following:

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

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

9 At least 2,000,000 renewable energy credits
10 for each delivery year shall come from new
11 photovoltaic projects; of that amount, to the
12 extent possible, the Agency shall procure: at
13 least 50% from solar photovoltaic projects using
14 the program outlined in subparagraph (K) of this
15 paragraph (1) from distributed renewable energy
16 generation devices or community renewable
17 generation projects; at least 40% from
18 utility-scale solar projects; at least 2% from
19 brownfield site photovoltaic projects that are not
20 community renewable generation projects; and the
21 remainder shall be determined through the
22 long-term planning process described in
23 subparagraph (A) of this paragraph (1); however,
24 if the long-term renewable resources procurement
25 plan includes the procurement of more than
26 2,000,000 renewable energy credits from new

1 photovoltaic projects, then the foregoing
2 allocations of renewable energy credits from the
3 program outlined in subparagraph (K) of this
4 paragraph (1), utility-scale solar projects, and
5 brownfield site photovoltaic projects that are not
6 community renewable generation projects shall not
7 apply to the portion of the renewable energy
8 credits procured in excess of the 2,000,000
9 renewable energy credits procured on behalf of
10 electric utilities that serve less than 3,000,000
11 retail customers but more than 500,000 retail
12 customers in this State and the allocation of such
13 procurement on behalf of electric utilities that
14 serve less than 3,000,000 retail customers but
15 more than 500,000 retail customers in this State
16 shall instead be based on the mix that produces the
17 lowest cost for the renewable energy credits
18 procured.

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

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

23 At least 3,000,000 renewable energy credits
24 for each delivery year shall come from new
25 photovoltaic projects; of that amount, to the
26 extent possible, the Agency shall procure: at

1 least 50% from solar photovoltaic projects using
2 the program outlined in subparagraph (K) of this
3 paragraph (1) from distributed renewable energy
4 devices or community renewable generation
5 projects; at least 40% from utility-scale solar
6 projects; at least 2% from brownfield site
7 photovoltaic projects that are not community
8 renewable generation projects; and the remainder
9 shall be determined through the long-term planning
10 process described in subparagraph (A) of this
11 paragraph (1); however, if the long-term renewable
12 resources procurement plan includes the
13 procurement of more than 3,000,000 renewable
14 energy credits from new photovoltaic projects,
15 then the foregoing allocations of renewable energy
16 credits from the program outlined in subparagraph
17 (K) of this paragraph (1), utility-scale solar
18 projects, and brownfield site photovoltaic
19 projects that are not community renewable
20 generation projects shall not apply to the portion
21 of the renewable energy credits procured in excess
22 of the 3,000,000 renewable energy credits procured
23 on behalf of electric utilities that serve less
24 than 3,000,000 retail customers but more than
25 500,000 retail customers in this State and the
26 allocation of such procurement on behalf of

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

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

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

10 At least 4,000,000 renewable energy credits
11 for each delivery year shall come from new
12 photovoltaic projects; of that amount, to the
13 extent possible, the Agency shall procure: at
14 least 50% from solar photovoltaic projects using
15 the program outlined in subparagraph (K) of this
16 paragraph (1) from distributed renewable energy
17 devices or community renewable generation
18 projects; at least 40% from utility-scale solar
19 projects; at least 2% from brownfield site
20 photovoltaic projects that are not community
21 renewable generation projects; and the remainder
22 shall be determined through the long-term planning
23 process described in subparagraph (A) of this
24 paragraph (1); however, if the long-term renewable
25 resources procurement plan includes the
26 procurement of more than 4,000,000 renewable

1 energy credits from new photovoltaic projects,
2 then the foregoing allocations of renewable energy
3 credits from the program outlined in subparagraph
4 (K) of this paragraph (1), utility-scale solar
5 projects, and brownfield site photovoltaic
6 projects that are not community renewable
7 generation projects shall not apply to the portion
8 of the renewable energy credits procured in excess
9 of the 4,000,000 renewable energy credits procured
10 on behalf of electric utilities that serve less
11 than 3,000,000 retail customers but more than
12 500,000 retail customers in this State and the
13 allocation of such procurement on behalf of
14 electric utilities that serve less than 3,000,000
15 retail customers but more than 500,000 retail
16 customers in this State shall instead be based on
17 the mix that produced the lowest cost for the
18 renewable energy credits procured.

19 For purposes of this Section:

20 "New wind projects" means wind renewable
21 energy facilities that are energized after June 1,
22 2017 for the delivery year commencing June 1, 2017
23 or within 3 years after the date the Commission
24 approves contracts for subsequent delivery years.

25 "New photovoltaic projects" means photovoltaic
26 renewable energy facilities that are energized

1 after June 1, 2017. Photovoltaic projects
2 developed under Section 1-56 of this Act shall not
3 apply towards the new photovoltaic project
4 requirements in this subparagraph (C).

5 (D) Renewable energy credits shall be cost effective.
6 For purposes of this subsection (c), "cost effective" means
7 that the costs of procuring renewable energy resources do
8 not cause the limit stated in subparagraph (E) of this
9 paragraph (1) to be exceeded and, for renewable energy
10 credits procured through a competitive procurement event,
11 do not exceed benchmarks based on market prices for like
12 products in the region. For purposes of this subsection
13 (c), "like products" means contracts for renewable energy
14 credits from the same or substantially similar technology,
15 same or substantially similar vintage (new or existing),
16 the same or substantially similar quantity, and the same or
17 substantially similar contract length and structure.
18 Benchmarks shall be developed by the procurement
19 administrator, in consultation with the Commission staff,
20 Agency staff, and the procurement monitor and shall be
21 subject to Commission review and approval. If price
22 benchmarks for like products in the region are not
23 available, the procurement administrator shall establish
24 price benchmarks based on publicly available data on
25 regional technology costs and expected current and future
26 regional energy prices. The benchmarks in this Section

1 shall not be used to curtail or otherwise reduce
2 contractual obligations entered into by or through the
3 Agency prior to June 1, 2017 (the effective date of Public
4 Act 99-906).

5 (E) For purposes of this subsection (c), the required
6 procurement of cost-effective renewable energy resources
7 for a particular year commencing prior to June 1, 2017
8 shall be measured as a percentage of the actual amount of
9 electricity (megawatt-hours) supplied by the electric
10 utility to eligible retail customers in the delivery year
11 ending immediately prior to the procurement, and, for
12 delivery years commencing on and after June 1, 2017, the
13 required procurement of cost-effective renewable energy
14 resources for a particular year shall be measured as a
15 percentage of the actual amount of electricity
16 (megawatt-hours) delivered by the electric utility in the
17 delivery year ending immediately prior to the procurement,
18 to all retail customers in its service territory. For
19 purposes of this subsection (c), the amount paid per
20 kilowatthour means the total amount paid for electric
21 service expressed on a per kilowatthour basis. For purposes
22 of this subsection (c), the total amount paid for electric
23 service includes without limitation amounts paid for
24 supply, transmission, distribution, surcharges, and add-on
25 taxes.

26 Notwithstanding the requirements of this subsection

1 (c), the total of renewable energy resources procured under
2 the procurement plan for any single year shall be subject
3 to the limitations of this subparagraph (E). Such
4 procurement shall be reduced for all retail customers based
5 on the amount necessary to limit the annual estimated
6 average net increase due to the costs of these resources
7 included in the amounts paid by eligible retail customers
8 in connection with electric service to no more than the
9 greater of 2.015% of the amount paid per kilowatthour by
10 those customers during the year ending May 31, 2007 or the
11 incremental amount per kilowatthour paid for these
12 resources in 2011; however, procurements that occur for
13 procurement periods that begin on or after June 1, 2026
14 shall be reduced for all retail customers of electric
15 utilities that serve less than 3,000,000 retail customers
16 but more than 500,000 retail customers in this State only
17 by an amount necessary to limit the annual estimated
18 average net increase due to the costs of these resources
19 included in the amounts paid by eligible retail customers
20 in connection with electric service to no more than the
21 greater of 2.515% of the amount paid per kilowatthour by
22 those customers during the year ending May 31, 2007 or the
23 incremental amount per kilowatthour paid for these
24 resources in 2011. To arrive at a maximum dollar amount of
25 renewable energy resources to be procured for the
26 particular delivery year, the resulting per kilowatthour

1 amount shall be applied to the actual amount of
2 kilowatthours of electricity delivered, or applicable
3 portion of such amount as specified in paragraph (1) of
4 this subsection (c), as applicable, by the electric utility
5 in the delivery year immediately prior to the procurement
6 to all retail customers in its service territory. The
7 calculations required by this subparagraph (E) shall be
8 made only once for each delivery year at the time that the
9 renewable energy resources are procured. Once the
10 determination as to the amount of renewable energy
11 resources to procure is made based on the calculations set
12 forth in this subparagraph (E) and the contracts procuring
13 those amounts are executed, no subsequent rate impact
14 determinations shall be made and no adjustments to those
15 contract amounts shall be allowed. All costs incurred under
16 such contracts shall be fully recoverable by the electric
17 utility as provided in this Section.

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

25 (i) renewable energy credits under existing
26 contractual obligations;

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

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

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

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

13 (i) Notwithstanding whether a long-term renewable
14 resources procurement plan has been approved, the
15 Agency shall conduct an initial forward procurement
16 for renewable energy credits from new utility-scale
17 wind projects within 160 days after June 1, 2017 (the
18 effective date of Public Act 99-906). For the purposes
19 of this initial forward procurement, the Agency shall
20 solicit 15-year contracts for delivery of 1,000,000
21 renewable energy credits delivered annually from new
22 utility-scale wind projects to begin delivery on June
23 1, 2019, if available, but not later than June 1, 2021,
24 unless the project has delays in the establishment of
25 an operating interconnection with the applicable
26 transmission or distribution system as a result of the

1 actions or inactions of the transmission or
2 distribution provider, or other causes for force
3 majeure as outlined in the procurement contract, in
4 which case, not later than June 1, 2022. Payments to
5 suppliers of renewable energy credits shall commence
6 upon delivery. Renewable energy credits procured under
7 this initial procurement shall be included in the
8 Agency's long-term plan and shall apply to all
9 renewable energy goals in this subsection (c).

10 (ii) Notwithstanding whether a long-term renewable
11 resources procurement plan has been approved, the
12 Agency shall conduct an initial forward procurement
13 for renewable energy credits from new utility-scale
14 solar projects and brownfield site photovoltaic
15 projects within one year after June 1, 2017 (the
16 effective date of Public Act 99-906). For the purposes
17 of this initial forward procurement, the Agency shall
18 solicit 15-year contracts for delivery of 1,000,000
19 renewable energy credits delivered annually from new
20 utility-scale solar projects and brownfield site
21 photovoltaic projects to begin delivery on June 1,
22 2019, if available, but not later than June 1, 2021,
23 unless the project has delays in the establishment of
24 an operating interconnection with the applicable
25 transmission or distribution system as a result of the
26 actions or inactions of the transmission or

1 distribution provider, or other causes for force
2 majeure as outlined in the procurement contract, in
3 which case, not later than June 1, 2022. The Agency may
4 structure this initial procurement in one or more
5 discrete procurement events. Payments to suppliers of
6 renewable energy credits shall commence upon delivery.
7 Renewable energy credits procured under this initial
8 procurement shall be included in the Agency's
9 long-term plan and shall apply to all renewable energy
10 goals in this subsection (c).

11 (iii) Subsequent forward procurements for
12 utility-scale wind projects shall solicit at least
13 1,000,000 renewable energy credits delivered annually
14 per procurement event and shall be planned, scheduled,
15 and designed such that the cumulative amount of
16 renewable energy credits delivered from all new wind
17 projects in each delivery year shall not exceed the
18 Agency's projection of the cumulative amount of
19 renewable energy credits that will be delivered from
20 all new photovoltaic projects, including utility-scale
21 and distributed photovoltaic devices, in the same
22 delivery year at the time scheduled for wind contract
23 delivery.

24 (iv) If, at any time after the time set for
25 delivery of renewable energy credits pursuant to the
26 initial procurements in items (i) and (ii) of this

1 subparagraph (G), the cumulative amount of renewable
2 energy credits projected to be delivered from all new
3 wind projects in a given delivery year exceeds the
4 cumulative amount of renewable energy credits
5 projected to be delivered from all new photovoltaic
6 projects in that delivery year by 200,000 or more
7 renewable energy credits, then the Agency shall within
8 60 days adjust the procurement programs in the
9 long-term renewable resources procurement plan to
10 ensure that the projected cumulative amount of
11 renewable energy credits to be delivered from all new
12 wind projects does not exceed the projected cumulative
13 amount of renewable energy credits to be delivered from
14 all new photovoltaic projects by 200,000 or more
15 renewable energy credits, provided that nothing in
16 this Section shall preclude the projected cumulative
17 amount of renewable energy credits to be delivered from
18 all new photovoltaic projects from exceeding the
19 projected cumulative amount of renewable energy
20 credits to be delivered from all new wind projects in
21 each delivery year and provided further that nothing in
22 this item (iv) shall require the curtailment of an
23 executed contract. The Agency shall update, on a
24 quarterly basis, its projection of the renewable
25 energy credits to be delivered from all projects in
26 each delivery year. Notwithstanding anything to the

1 contrary, the Agency may adjust the timing of
2 procurement events conducted under this subparagraph
3 (G). The long-term renewable resources procurement
4 plan shall set forth the process by which the
5 adjustments may be made.

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

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

20 (i) Within 45 days after June 1, 2017 (the
21 effective date of Public Act 99-906), an alternative
22 retail electric supplier or its successor shall submit
23 an informational filing to the Illinois Commerce
24 Commission certifying that, as of December 31, 2015,
25 the alternative retail electric supplier owned one or
26 more electric generating facilities that generates

1 renewable energy resources as defined in Section 1-10
2 of this Act, provided that such facilities are not
3 powered by wind or photovoltaics, and the facilities
4 generate one renewable energy credit for each
5 megawatthour of energy produced from the facility.

6 The informational filing shall identify each
7 facility that was eligible to satisfy the alternative
8 retail electric supplier's obligations under Section
9 16-115D of the Public Utilities Act as described in
10 this item (i).

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

17 (iii) The alternative retail electric supplier
18 shall notify the Agency and the applicable utility, no
19 later than February 28 of the year preceding the
20 applicable delivery year or 15 days after June 1, 2017
21 (the effective date of Public Act 99-906), whichever is
22 later, of its election under item (ii) of this
23 subparagraph (H) to supply renewable energy credits to
24 retail customers of the utility. Such election shall
25 identify the amount of renewable energy credits to be
26 supplied by the alternative retail electric supplier

1 to the utility's retail customers and the source of the
2 renewable energy credits identified in the
3 informational filing as described in item (i) of this
4 subparagraph (H), subject to the following
5 limitations:

6 For the delivery year beginning June 1, 2018,
7 the maximum amount of renewable energy credits to
8 be supplied by an alternative retail electric
9 supplier under this subparagraph (H) shall be 68%
10 multiplied by 25% multiplied by 14.5% multiplied
11 by the amount of metered electricity
12 (megawatt-hours) delivered by the alternative
13 retail electric supplier to Illinois retail
14 customers during the delivery year ending May 31,
15 2016.

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

1 thereafter to 25% by the delivery year beginning
2 June 1, 2025, and thereafter the 25% value shall
3 apply to each delivery year.

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

17 If the requirements set forth in items (i) through
18 (iii) of this subparagraph (H) are met, the charges
19 that would otherwise be applicable to the retail
20 customers of the alternative retail electric supplier
21 under paragraph (6) of this subsection (c) for the
22 applicable delivery year shall be reduced by the ratio
23 of the quantity of renewable energy credits supplied by
24 the alternative retail electric supplier compared to
25 that supplier's target renewable energy credit
26 quantity. The supplier's target renewable energy

1 credit quantity for the delivery year beginning June 1,
2 2018 is 14.5% multiplied by the total amount of metered
3 electricity (megawatt-hours) delivered by the
4 alternative retail supplier in that delivery year,
5 provided that the 14.5% shall increase by 1.5% each
6 delivery year thereafter to 25% by the delivery year
7 beginning June 1, 2025, and thereafter the 25% value
8 shall apply to each delivery year.

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

14 (I) The Agency shall design its long-term renewable
15 energy procurement plan to maximize the State's interest in
16 the health, safety, and welfare of its residents, including
17 but not limited to minimizing sulfur dioxide, nitrogen
18 oxide, particulate matter and other pollution that
19 adversely affects public health in this State, increasing
20 fuel and resource diversity in this State, enhancing the
21 reliability and resiliency of the electricity distribution
22 system in this State, meeting goals to limit carbon dioxide
23 emissions under federal or State law, and contributing to a
24 cleaner and healthier environment for the citizens of this
25 State, while balancing these goals with the requirement to
26 minimize the cost to customers attributable to the

1 procurement of renewable energy credits set forth in
2 subparagraph (C) of paragraph (1) of this subsection (c).

3 In order to further these legislative purposes, renewable
4 energy credits shall be eligible to be counted toward the
5 renewable energy requirements of this subsection (c) if
6 they are generated from facilities located in this State.
7 The Agency may qualify renewable energy credits from
8 facilities located in states adjacent to Illinois if the
9 generator demonstrates and the Agency determines that the
10 operation of such facility or facilities will help promote
11 the State's interest in the health, safety, and welfare of
12 its residents based on the public interest criteria
13 described above. To ensure that the public interest
14 criteria are applied to the procurement and given full
15 effect, the Agency's long-term procurement plan shall
16 describe in detail how each public interest factor shall be
17 considered and weighted for facilities located in states
18 adjacent to Illinois.

19 (J) In order to promote the competitive development of
20 renewable energy resources in furtherance of the State's
21 interest in the health, safety, and welfare of its
22 residents, renewable energy credits shall not be eligible
23 to be counted toward the renewable energy requirements of
24 this subsection (c) if they are sourced from a generating
25 unit whose costs were being recovered through rates
26 regulated by this State or any other state or states on or

1 after January 1, 2017. Each contract executed to purchase
2 renewable energy credits under this subsection (c) shall
3 provide for the contract's termination if the costs of the
4 generating unit supplying the renewable energy credits
5 subsequently begin to be recovered through rates regulated
6 by this State or any other state or states; and each
7 contract shall further provide that, in that event, the
8 supplier of the credits must return 110% of all payments
9 received under the contract. Amounts returned under the
10 requirements of this subparagraph (J) shall be retained by
11 the utility and all of these amounts shall be used for the
12 procurement of additional renewable energy credits from
13 new wind or new photovoltaic resources as defined in this
14 subsection (c). The long-term plan shall provide that these
15 renewable energy credits shall be procured in the next
16 procurement event.

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

25 (K) The long-term renewable resources procurement plan
26 developed by the Agency in accordance with subparagraph (A)

1 of this paragraph (1) shall include an Adjustable Block
2 program for the procurement of renewable energy credits
3 from new photovoltaic projects that are distributed
4 renewable energy generation devices or new photovoltaic
5 community renewable generation projects on behalf of
6 electric utilities that serve more than 3,000,000 retail
7 customers or less than 500,000 retail customers in this
8 State and a competitive procurement process for the
9 procurement of new photovoltaic community renewable
10 generation projects on behalf of electric utilities that
11 serve less than 3,000,000 retail customers but more than
12 500,000 retail customers in this State. The Adjustable
13 Block program shall be designed to provide a transparent
14 schedule of prices and quantities to enable the
15 photovoltaic market to scale up and for renewable energy
16 credit prices to adjust at a predictable rate over time.
17 The prices set by the Adjustable Block program can be
18 reflected as a set value or as the product of a formula.

19 The Adjustable Block program shall include for each
20 category of eligible projects: a schedule of standard block
21 purchase prices to be offered; a series of steps, with
22 associated nameplate capacity and purchase prices that
23 adjust from step to step; and automatic opening of the next
24 step as soon as the nameplate capacity and available
25 purchase prices for an open step are fully committed or
26 reserved. Only projects energized on or after June 1, 2017

1 shall be eligible for the Adjustable Block program. For
2 each block group the Agency shall determine the number of
3 blocks, the amount of generation capacity in each block,
4 and the purchase price for each block, provided that the
5 purchase price provided and the total amount of generation
6 in all blocks for all block groups shall be sufficient to
7 meet the goals in this subsection (c). The Agency may
8 periodically review its prior decisions establishing the
9 number of blocks, the amount of generation capacity in each
10 block, and the purchase price for each block, and may
11 propose, on an expedited basis, changes to these previously
12 set values, including but not limited to redistributing
13 these amounts and the available funds as necessary and
14 appropriate, subject to Commission approval as part of the
15 periodic plan revision process described in Section
16 16-111.5 of the Public Utilities Act. The Agency may define
17 different block sizes, purchase prices, or other distinct
18 terms and conditions for projects located in different
19 utility service territories if the Agency deems it
20 necessary to meet the goals in this subsection (c);
21 however, if, for any block to be procured on behalf of
22 electric utilities that serve less than 3,000,000 retail
23 customers but more than 500,000 retail customers in this
24 State, the quantity of renewable energy credits sought by
25 eligible projects exceeds the quantity of renewable energy
26 credits defined by the Agency for the block, the Agency

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

9 The competitive procurement process used for the
10 procurement of new photovoltaic community renewable
11 generation projects on behalf of electric utilities that
12 serve less than 3,000,000 retail customers but more than
13 500,000 retail customers in this State shall define the
14 quantity of renewable energy credits to be procured and
15 allow bidders to submit price offers to the Agency. The
16 Agency shall conduct the competitive procurement process
17 in a manner that results in the lowest cost for the
18 renewable energy credits procured.

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

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

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

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

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

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

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

24 (i) The Agency shall procure contracts of at least
25 15 years in length.

26 (ii) For those renewable energy credits that

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

10 (iii) For those renewable energy credits that
11 qualify and are procured under item (ii) and (iii) of
12 subparagraph (K) of this paragraph (1) and any
13 additional categories of distributed generation
14 included in the long-term renewable resources
15 procurement plan and approved by the Commission, 20
16 percent of the renewable energy credit purchase price
17 shall be paid by the contracting utilities at the time
18 that the facility producing the renewable energy
19 credits is interconnected at the distribution system
20 level of the utility and energized. The remaining
21 portion shall be paid ratably over the subsequent
22 4-year period. The electric utility shall receive and
23 retire all renewable energy credits generated by the
24 project for the first 15 years of operation.

25 (iv) Each contract shall include provisions to
26 ensure the delivery of the renewable energy credits for

1 the full term of the contract.

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

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

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

26 (M) The Agency shall be authorized to retain one or

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

15 The Agency and its consultant or consultants shall
16 monitor block activity, share program activity with
17 stakeholders and conduct regularly scheduled meetings to
18 discuss program activity and market conditions. If
19 necessary, the Agency may make prospective administrative
20 adjustments to the Adjustable Block program design, such as
21 redistributing available funds or making adjustments to
22 purchase prices as necessary to achieve the goals of this
23 subsection (c). Program modifications to any price,
24 capacity block, or other program element that do not
25 deviate from the Commission's approved value by more than
26 25% shall take effect immediately and are not subject to

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

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

1 service territory.

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

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

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

1 (O) For the delivery year beginning June 1, 2018, the
2 long-term renewable resources procurement plan required by
3 this subsection (c) shall provide for the Agency to procure
4 contracts to continue offering the Illinois Solar for All
5 Program described in subsection (b) of Section 1-56 of this
6 Act, and the contracts approved by the Commission shall be
7 executed by the utilities that are subject to this
8 subsection (c). The long-term renewable resources
9 procurement plan shall allocate 5% of the funds available
10 under the plan for the applicable delivery year, or
11 \$10,000,000 per delivery year, whichever is greater, to
12 fund the programs, and the plan shall determine the amount
13 of funding to be apportioned to the programs identified in
14 subsection (b) of Section 1-56 of this Act; provided that
15 for the delivery years beginning June 1, 2017, June 1,
16 2021, and June 1, 2025, the long-term renewable resources
17 procurement plan shall allocate 10% of the funds available
18 under the plan for the applicable delivery year, or
19 \$20,000,000 per delivery year, whichever is greater, and
20 \$10,000,000 of such funds in such year shall be used by an
21 electric utility that serves more than 3,000,000 retail
22 customers in the State to implement a Commission-approved
23 plan under Section 16-108.12 of the Public Utilities Act.
24 In making the determinations required under this
25 subparagraph (O), the Commission shall consider the
26 experience and performance under the programs and any

1 evaluation reports. The Commission shall also provide for
2 an independent evaluation of those programs on a periodic
3 basis that are funded under this subparagraph (O).

4 (2) (Blank).

5 (3) (Blank).

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

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

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

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

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

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

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

9 (d) Clean coal portfolio standard.

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

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

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

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

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

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

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

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

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

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

25 (C) in 2012, the greater of an additional 0.5% of
26 the amount paid per kilowatthour by those customers

1 during the year ending May 31, 2011 or 1.5% of the
2 amount paid per kilowatthour by those customers during
3 the year ending May 31, 2009;

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

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

22 No later than June 30, 2015, the Commission shall
23 review the limitation on the total amount paid under
24 sourcing agreements, if any, with clean coal facilities
25 pursuant to this subsection (d) and report to the General
26 Assembly its findings as to whether that limitation unduly

1 constrains the amount of electricity generated by
2 cost-effective clean coal facilities that is covered by
3 sourcing agreements.

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

26 (A) a formula contractual price (the "contract

1 price") approved pursuant to paragraph (4) of this
2 subsection (d), which shall:

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

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

1 requirement for this initial clean coal facility;

2 (B) power purchase provisions, which shall:

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

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

10 (iii) require the utility party to such
11 sourcing agreement to buy from the initial clean
12 coal facility in each hour an amount of energy
13 equal to all clean coal energy made available from
14 the initial clean coal facility during such hour
15 times a fraction, the numerator of which is such
16 utility's retail market sales of electricity
17 (expressed in kilowatthours sold) in the State
18 during the prior calendar month and the
19 denominator of which is the total retail market
20 sales of electricity (expressed in kilowatthours
21 sold) in the State by utilities during such prior
22 month and the sales of electricity (expressed in
23 kilowatthours sold) in the State by alternative
24 retail electric suppliers during such prior month
25 that are subject to the requirements of this
26 subsection (d) and paragraph (5) of subsection (d)

1 of Section 16-115 of the Public Utilities Act,
2 provided that the amount purchased by the utility
3 in any year will be limited by paragraph (2) of
4 this subsection (d); and

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

8 (C) contract for differences provisions, which
9 shall:

10 (i) require the utility party to such sourcing
11 agreement to contract with the initial clean coal
12 facility in each hour with respect to an amount of
13 energy equal to all clean coal energy made
14 available from the initial clean coal facility
15 during such hour times a fraction, the numerator of
16 which is such utility's retail market sales of
17 electricity (expressed in kilowatthours sold) in
18 the utility's service territory in the State
19 during the prior calendar month and the
20 denominator of which is the total retail market
21 sales of electricity (expressed in kilowatthours
22 sold) in the State by utilities during such prior
23 month and the sales of electricity (expressed in
24 kilowatthours sold) in the State by alternative
25 retail electric suppliers during such prior month
26 that are subject to the requirements of this

1 subsection (d) and paragraph (5) of subsection (d)
2 of Section 16-115 of the Public Utilities Act,
3 provided that the amount paid by the utility in any
4 year will be limited by paragraph (2) of this
5 subsection (d);

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

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

1 (D) general provisions, which shall:

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

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

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

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

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

1 Commission each year, starting in the facility's
2 first year of commercial operation, accurately
3 reporting the quantity of carbon emissions from
4 the facility that have been captured and
5 sequestered and report any quantities of carbon
6 released from the site or sites at which carbon
7 emissions were sequestered in prior years, based
8 on continuous monitoring of such sites. If, in any
9 year after the first year of commercial operation,
10 the owner of the facility fails to demonstrate that
11 the initial clean coal facility captured and
12 sequestered at least 50% of the total carbon
13 emissions that the facility would otherwise emit
14 or that sequestration of emissions from prior
15 years has failed, resulting in the release of
16 carbon dioxide into the atmosphere, the owner of
17 the facility must offset excess emissions. Any
18 such carbon offsets must be permanent, additional,
19 verifiable, real, located within the State of
20 Illinois, and legally and practicably enforceable.
21 The cost of such offsets for the facility that are
22 not recoverable shall not exceed \$15 million in any
23 given year. No costs of any such purchases of
24 carbon offsets may be recovered from a utility or
25 its customers. All carbon offsets purchased for
26 this purpose and any carbon emission credits

1 associated with sequestration of carbon from the
2 facility must be permanently retired. The initial
3 clean coal facility shall not forfeit its
4 designation as a clean coal facility if the
5 facility fails to fully comply with the applicable
6 carbon sequestration requirements in any given
7 year, provided the requisite offsets are
8 purchased. However, the Attorney General, on
9 behalf of the People of the State of Illinois, may
10 specifically enforce the facility's sequestration
11 requirement and the other terms of this contract
12 provision. Compliance with the sequestration
13 requirements and offset purchase requirements
14 specified in paragraph (3) of this subsection (d)
15 shall be reviewed annually by an independent
16 expert retained by the owner of the initial clean
17 coal facility, with the advance written approval
18 of the Attorney General. The Commission may, in the
19 course of the review specified in item (vii),
20 reduce the allowable return on equity for the
21 facility if the facility willfully fails to comply
22 with the carbon capture and sequestration
23 requirements set forth in this item (v);

24 (vi) include limits on, and accordingly
25 provide for modification of, the amount the
26 utility is required to source under the sourcing

1 agreement consistent with paragraph (2) of this
2 subsection (d);

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

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

25 (ix) limit the utility's or alternative retail
26 electric supplier's obligation to incur any

1 liability until such time as the facility is in
2 commercial operation and generating power and
3 energy and such power and energy is being delivered
4 to the facility busbar;

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

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

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

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

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

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

19 (ii) Commission report. Within 6 months following
20 receipt of the facility cost report, the Commission, in
21 consultation with the Agency, shall submit a report to
22 the General Assembly setting forth its analysis of the
23 facility cost report. Such report shall include, but
24 not be limited to, a comparison of the costs associated
25 with electricity generated by the initial clean coal
26 facility to the costs associated with electricity

1 generated by other types of generation facilities, an
2 analysis of the rate impacts on residential and small
3 business customers over the life of the sourcing
4 agreements, and an analysis of the likelihood that the
5 initial clean coal facility will commence commercial
6 operation by and be delivering power to the facility's
7 busbar by 2016. To assist in the preparation of its
8 report, the Commission, in consultation with the
9 Agency, may hire one or more experts or consultants,
10 the costs of which shall be paid for by the owner of
11 the initial clean coal facility. The Commission and
12 Agency may begin the process of selecting such experts
13 or consultants prior to receipt of the facility cost
14 report.

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

26 (iv) Commission review. If the General Assembly

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

11 The facility cost report shall be prepared as follows:

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

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

26 (ii) an estimate of the capital cost of the

1 balance of the plant, including any capital costs
2 associated with sequestration of carbon dioxide
3 emissions and all interconnects and interfaces
4 required to operate the facility, such as
5 transmission of electricity, construction or
6 backfeed power supply, pipelines to transport
7 substitute natural gas or carbon dioxide, potable
8 water supply, natural gas supply, water supply,
9 water discharge, landfill, access roads, and coal
10 delivery.

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

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

25 (C) The facility cost report shall also include an
26 operating and maintenance cost quote that will provide

1 the estimated cost of delivered fuel, personnel,
2 maintenance contracts, chemicals, catalysts,
3 consumables, spares, and other fixed and variable
4 operations and maintenance costs. The delivered fuel
5 cost estimate will be provided by a recognized third
6 party expert or experts in the fuel and transportation
7 industries. The balance of the operating and
8 maintenance cost quote, excluding delivered fuel
9 costs, will be developed based on the inputs provided
10 by duly licensed engineering and construction firms
11 performing the construction cost quote, potential
12 vendors under long-term service agreements and plant
13 operating agreements, or recognized third party plant
14 operator or operators.

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

23 (D) The facility cost report shall also include an
24 analysis of the initial clean coal facility's ability
25 to deliver power and energy into the applicable
26 regional transmission organization markets and an

1 analysis of the expected capacity factor for the
2 initial clean coal facility.

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

9 (5) Re-powering and retrofitting coal-fired power
10 plants previously owned by Illinois utilities to qualify as
11 clean coal facilities. During the 2009 procurement
12 planning process and thereafter, the Agency and the
13 Commission shall consider sourcing agreements covering
14 electricity generated by power plants that were previously
15 owned by Illinois utilities and that have been or will be
16 converted into clean coal facilities, as defined by Section
17 1-10 of this Act. Pursuant to such procurement planning
18 process, the owners of such facilities may propose to the
19 Agency sourcing agreements with utilities and alternative
20 retail electric suppliers required to comply with
21 subsection (d) of this Section and item (5) of subsection
22 (d) of Section 16-115 of the Public Utilities Act, covering
23 electricity generated by such facilities. In the case of
24 sourcing agreements that are power purchase agreements,
25 the contract price for electricity sales shall be
26 established on a cost of service basis. In the case of

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

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

18 (d-5) Zero emission standard.

19 (1) Beginning with the delivery year commencing on June
20 1, 2017, the Agency shall, for electric utilities that
21 serve at least 100,000 retail customers in this State,
22 procure contracts with zero emission facilities that are
23 reasonably capable of generating cost-effective zero
24 emission credits in an amount approximately equal to 16% of
25 the actual amount of electricity delivered by each electric
26 utility to retail customers in the State during calendar

1 year 2014. For an electric utility serving fewer than
2 100,000 retail customers in this State that requested,
3 under Section 16-111.5 of the Public Utilities Act, that
4 the Agency procure power and energy for all or a portion of
5 the utility's Illinois load for the delivery year
6 commencing June 1, 2016, the Agency shall procure contracts
7 with zero emission facilities that are reasonably capable
8 of generating cost-effective zero emission credits in an
9 amount approximately equal to 16% of the portion of power
10 and energy to be procured by the Agency for the utility.
11 The duration of the contracts procured under this
12 subsection (d-5) shall be for a term of 10 years ending May
13 31, 2027. The quantity of zero emission credits to be
14 procured under the contracts shall be all of the zero
15 emission credits generated by the zero emission facility in
16 each delivery year; however, if the zero emission facility
17 is owned by more than one entity, then the quantity of zero
18 emission credits to be procured under the contracts shall
19 be the amount of zero emission credits that are generated
20 from the portion of the zero emission facility that is
21 owned by the winning supplier.

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

26 The procurement process shall be subject to the

1 following provisions:

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

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

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

15 (iii) the annual zero emission facility cost
16 projections, expressed on a per megawatthour
17 basis, over the next 6 delivery years, which shall
18 include the following: operation and maintenance
19 expenses; fully allocated overhead costs, which
20 shall be allocated using the methodology developed
21 by the Institute for Nuclear Power Operations;
22 fuel expenditures; non-fuel capital expenditures;
23 spent fuel expenditures; a return on working
24 capital; the cost of operational and market risks
25 that could be avoided by ceasing operation; and any
26 other costs necessary for continued operations,

1 provided that "necessary" means, for purposes of
2 this item (iii), that the costs could reasonably be
3 avoided only by ceasing operations of the zero
4 emission facility; and

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

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

22 (B) The price for each zero emission credit
23 procured under this subsection (d-5) for each delivery
24 year shall be in an amount that equals the Social Cost
25 of Carbon, expressed on a price per megawatthour basis.
26 However, to ensure that the procurement remains

1 affordable to retail customers in this State if
2 electricity prices increase, the price in an
3 applicable delivery year shall be reduced below the
4 Social Cost of Carbon by the amount ("Price
5 Adjustment") by which the market price index for the
6 applicable delivery year exceeds the baseline market
7 price index for the consecutive 12-month period ending
8 May 31, 2016. If the Price Adjustment is greater than
9 or equal to the Social Cost of Carbon in an applicable
10 delivery year, then no payments shall be due in that
11 delivery year. The components of this calculation are
12 defined as follows:

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

24 (ii) Baseline market price index: The baseline
25 market price index for the consecutive 12-month
26 period ending May 31, 2016 is \$31.40 per

1 megawatthour, which is based on the sum of (aa) the
2 average day-ahead energy price across all hours of
3 such 12-month period at the PJM Interconnection
4 LLC Northern Illinois Hub, (bb) 50% multiplied by
5 the Base Residual Auction, or its successor,
6 capacity price for the rest of the RTO zone group
7 determined by PJM Interconnection LLC, divided by
8 24 hours per day, and (cc) 50% multiplied by the
9 Planning Resource Auction, or its successor,
10 capacity price for Zone 4 determined by the
11 Midcontinent Independent System Operator, Inc.,
12 divided by 24 hours per day.

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

17 (aa) Projected energy prices: the
18 projected energy prices for the applicable
19 delivery year shall be calculated once for the
20 year using the forward market price for the PJM
21 Interconnection, LLC Northern Illinois Hub.
22 The forward market price shall be calculated as
23 follows: the energy forward prices for each
24 month of the applicable delivery year averaged
25 for each trade date during the calendar year
26 immediately preceding that delivery year to

1 produce a single energy forward price for the
2 delivery year. The forward market price
3 calculation shall use data published by the
4 Intercontinental Exchange, or its successor.

5 (bb) Projected capacity prices:

6 (I) For the delivery years commencing
7 June 1, 2017, June 1, 2018, and June 1,
8 2019, the projected capacity price shall
9 be equal to the sum of (1) 50% multiplied
10 by the Base Residual Auction, or its
11 successor, price for the rest of the RTO
12 zone group as determined by PJM
13 Interconnection LLC, divided by 24 hours
14 per day and, (2) 50% multiplied by the
15 resource auction price determined in the
16 resource auction administered by the
17 Midcontinent Independent System Operator,
18 Inc., in which the largest percentage of
19 load cleared for Local Resource Zone 4,
20 divided by 24 hours per day, and where such
21 price is determined by the Midcontinent
22 Independent System Operator, Inc.

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

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

13 For purposes of this subsection (d-5):

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

17 "RTO" means regional transmission
18 organization.

19 (C) No later than 45 days after June 1, 2017 (the
20 effective date of Public Act 99-906), the Agency shall
21 publish its proposed zero emission standard
22 procurement plan. The plan shall be consistent with the
23 provisions of this paragraph (1) and shall provide that
24 winning bids shall be selected based on public interest
25 criteria that include, but are not limited to,
26 minimizing carbon dioxide emissions that result from

1 electricity consumed in Illinois and minimizing sulfur
2 dioxide, nitrogen oxide, and particulate matter
3 emissions that adversely affect the citizens of this
4 State. In particular, the selection of winning bids
5 shall take into account the incremental environmental
6 benefits resulting from the procurement, such as any
7 existing environmental benefits that are preserved by
8 the procurements held under Public Act 99-906 and would
9 cease to exist if the procurements were not held,
10 including the preservation of zero emission
11 facilities. The plan shall also describe in detail how
12 each public interest factor shall be considered and
13 weighted in the bid selection process to ensure that
14 the public interest criteria are applied to the
15 procurement and given full effect.

16 For purposes of developing the plan, the Agency
17 shall consider any reports issued by a State agency,
18 board, or commission under House Resolution 1146 of the
19 98th General Assembly and paragraph (4) of subsection
20 (d) of this Section, as well as publicly available
21 analyses and studies performed by or for regional
22 transmission organizations that serve the State and
23 their independent market monitors.

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

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

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

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

24 (i) identify how the winning bids satisfy the
25 public interest criteria described in subparagraph
26 (C) of this paragraph (1) of minimizing carbon

1 dioxide emissions that result from electricity
2 consumed in Illinois and minimizing sulfur
3 dioxide, nitrogen oxide, and particulate matter
4 emissions that adversely affect the citizens of
5 this State;

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

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

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

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

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

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

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

26 Each utility shall enter into binding contractual

1 arrangements with the winning suppliers.

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

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

1 every May 25 thereafter.

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

8 (i) A zero emission facility shall be excused
9 from its performance under the contract for any
10 cause beyond the control of the resource,
11 including, but not restricted to, acts of God,
12 flood, drought, earthquake, storm, fire,
13 lightning, epidemic, war, riot, civil disturbance
14 or disobedience, labor dispute, labor or material
15 shortage, sabotage, acts of public enemy,
16 explosions, orders, regulations or restrictions
17 imposed by governmental, military, or lawfully
18 established civilian authorities, which, in any of
19 the foregoing cases, by exercise of commercially
20 reasonable efforts the zero emission facility
21 could not reasonably have been expected to avoid,
22 and which, by the exercise of commercially
23 reasonable efforts, it has been unable to
24 overcome. In such event, the zero emission
25 facility shall be excused from performance for the
26 duration of the event, including, but not limited

1 to, delivery of zero emission credits, and no
2 payment shall be due to the zero emission facility
3 during the duration of the event.

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

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

24 (iv) A zero emission facility shall be
25 permitted to terminate the contract in the event
26 the Nuclear Regulatory Commission terminates the

1 resource's license.

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

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

18 Notwithstanding the requirements of this subsection
19 (d-5), the contracts executed under this subsection (d-5)
20 shall provide that the total of zero emission credits
21 procured under a procurement plan shall be subject to the
22 limitations of this paragraph (2). For each delivery year,
23 the contractual volume receiving payments in such year
24 shall be reduced for all retail customers based on the
25 amount necessary to limit the net increase that delivery
26 year to the costs of those credits included in the amounts

1 paid by eligible retail customers in connection with
2 electric service to no more than 1.65% of the amount paid
3 per kilowatthour by eligible retail customers during the
4 year ending May 31, 2009. The result of this computation
5 shall apply to and reduce the procurement for all retail
6 customers, and all those customers shall pay the same
7 single, uniform cents per kilowatthour charge under
8 subsection (k) of Section 16-108 of the Public Utilities
9 Act. To arrive at a maximum dollar amount of zero emission
10 credits to be paid for the particular delivery year, the
11 resulting per kilowatthour amount shall be applied to the
12 actual amount of kilowatthours of electricity delivered by
13 the electric utility in the delivery year immediately prior
14 to the procurement, to all retail customers in its service
15 territory. Unpaid contractual volume for any delivery year
16 shall be paid in any subsequent delivery year in which such
17 payments can be made without exceeding the amount specified
18 in this paragraph (2). The calculations required by this
19 paragraph (2) shall be made only once for each procurement
20 plan year. Once the determination as to the amount of zero
21 emission credits to be paid is made based on the
22 calculations set forth in this paragraph (2), no subsequent
23 rate impact determinations shall be made and no adjustments
24 to those contract amounts shall be allowed. All costs
25 incurred under those contracts and in implementing this
26 subsection (d-5) shall be recovered by the electric utility

1 as provided in this Section.

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

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

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

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

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

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

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

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

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

4 (6) Electric utilities shall be entitled to recover all
5 of the costs associated with the procurement of zero
6 emission credits through an automatic adjustment clause
7 tariff in accordance with subsection (k) and (m) of Section
8 16-108 of the Public Utilities Act, and the contracts
9 executed under this subsection (d-5) shall provide that the
10 utilities' payment obligations under such contracts shall
11 be reduced if an adjustment is required under subsection
12 (m) of Section 16-108 of the Public Utilities Act.

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

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

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

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

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

1 process.

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

14 (Source: P.A. 100-863, eff. 8-14-18; 101-81, eff. 7-12-19;
15 101-113, eff. 1-1-20.)

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

19 (220 ILCS 5/8-103B)

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

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

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

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

21 (b) For purposes of this Section, electric utilities
22 subject to this Section that serve more than 3,000,000 retail
23 customers in the State shall be deemed to have achieved a
24 cumulative persisting annual savings of 6.6% from energy
25 efficiency measures and programs implemented during the period
26 beginning January 1, 2012 and ending December 31, 2017, which

1 percent is based on the deemed average weather normalized sales
2 of electric power and energy during calendar years 2014, 2015,
3 and 2016 of 88,000,000 MWhs. For the purposes of this
4 subsection (b) and subsection (b-5), the 88,000,000 MWhs of
5 deemed electric power and energy sales shall be reduced by the
6 number of MWhs equal to the sum of the annual consumption of
7 customers that are exempt from subsections (a) through (j) of
8 this Section under subsection (l) of this Section, as averaged
9 across the calendar years 2014, 2015, and 2016. After 2017, the
10 deemed value of cumulative persisting annual savings from
11 energy efficiency measures and programs implemented during the
12 period beginning January 1, 2012 and ending December 31, 2017,
13 shall be reduced each year, as follows, and the applicable
14 value shall be applied to and count toward the utility's
15 achievement of the cumulative persisting annual savings goals
16 set forth in subsection (b-5):

17 (1) 5.8% deemed cumulative persisting annual savings
18 for the year ending December 31, 2018;

19 (2) 5.2% deemed cumulative persisting annual savings
20 for the year ending December 31, 2019;

21 (3) 4.5% deemed cumulative persisting annual savings
22 for the year ending December 31, 2020;

23 (4) 4.0% deemed cumulative persisting annual savings
24 for the year ending December 31, 2021;

25 (5) 3.5% deemed cumulative persisting annual savings
26 for the year ending December 31, 2022;

1 (6) 3.1% deemed cumulative persisting annual savings
2 for the year ending December 31, 2023;

3 (7) 2.8% deemed cumulative persisting annual savings
4 for the year ending December 31, 2024;

5 (8) 2.5% deemed cumulative persisting annual savings
6 for the year ending December 31, 2025;

7 (9) 2.3% deemed cumulative persisting annual savings
8 for the year ending December 31, 2026;

9 (10) 2.1% deemed cumulative persisting annual savings
10 for the year ending December 31, 2027;

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

13 (12) 1.7% deemed cumulative persisting annual savings
14 for the year ending December 31, 2029; and

15 (13) 1.5% deemed cumulative persisting annual savings
16 for the year ending December 31, 2030.

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

23 (b-5) Beginning in 2018, electric utilities subject to this
24 Section that serve more than 3,000,000 retail customers in the
25 State shall achieve the following cumulative persisting annual
26 savings goals, as modified by subsection (f) of this Section

1 and as compared to the deemed baseline of 88,000,000 MWhs of
2 electric power and energy sales set forth in subsection (b), as
3 reduced by the number of MWhs equal to the sum of the annual
4 consumption of customers that are exempt from subsections (a)
5 through (j) of this Section under subsection (l) of this
6 Section as averaged across the calendar years 2014, 2015, and
7 2016, through the implementation of energy efficiency measures
8 during the applicable year and in prior years, but no earlier
9 than January 1, 2012:

10 (1) 7.8% cumulative persisting annual savings for the
11 year ending December 31, 2018;

12 (2) 9.1% cumulative persisting annual savings for the
13 year ending December 31, 2019;

14 (3) 10.4% cumulative persisting annual savings for the
15 year ending December 31, 2020;

16 (4) 11.8% cumulative persisting annual savings for the
17 year ending December 31, 2021;

18 (5) 13.1% cumulative persisting annual savings for the
19 year ending December 31, 2022;

20 (6) 14.4% cumulative persisting annual savings for the
21 year ending December 31, 2023;

22 (7) 15.7% cumulative persisting annual savings for the
23 year ending December 31, 2024;

24 (8) 17% cumulative persisting annual savings for the
25 year ending December 31, 2025;

26 (9) 17.9% cumulative persisting annual savings for the

1 year ending December 31, 2026;

2 (10) 18.8% cumulative persisting annual savings for
3 the year ending December 31, 2027;

4 (11) 19.7% cumulative persisting annual savings for
5 the year ending December 31, 2028;

6 (12) 20.6% cumulative persisting annual savings for
7 the year ending December 31, 2029; and

8 (13) 21.5% cumulative persisting annual savings for
9 the year ending December 31, 2030.

10 (b-10) For purposes of this Section, electric utilities
11 subject to this Section that serve less than 3,000,000 retail
12 customers but more than 500,000 retail customers in the State
13 shall be deemed to have achieved a cumulative persisting annual
14 savings of 6.6% from energy efficiency measures and programs
15 implemented during the period beginning January 1, 2012 and
16 ending December 31, 2017, which is based on the deemed average
17 weather normalized sales of electric power and energy during
18 calendar years 2014, 2015, and 2016 of 36,900,000 MWhs. For the
19 purposes of this subsection (b-10) and subsection (b-15), the
20 36,900,000 MWhs of deemed electric power and energy sales shall
21 be reduced by the number of MWhs equal to the sum of the annual
22 consumption of customers that are exempt from subsections (a)
23 through (j) of this Section under subsection (1) of this
24 Section, as averaged across the calendar years 2014, 2015, and
25 2016. After 2017, the deemed value of cumulative persisting
26 annual savings from energy efficiency measures and programs

1 implemented during the period beginning January 1, 2012 and
2 ending December 31, 2017, shall be reduced each year, as
3 follows, and the applicable value shall be applied to and count
4 toward the utility's achievement of the cumulative persisting
5 annual savings goals set forth in subsection (b-15):

6 (1) 5.8% deemed cumulative persisting annual savings
7 for the year ending December 31, 2018;

8 (2) 5.2% deemed cumulative persisting annual savings
9 for the year ending December 31, 2019;

10 (3) 4.5% deemed cumulative persisting annual savings
11 for the year ending December 31, 2020;

12 (4) 4.0% deemed cumulative persisting annual savings
13 for the year ending December 31, 2021;

14 (5) 3.5% deemed cumulative persisting annual savings
15 for the year ending December 31, 2022;

16 (6) 3.1% deemed cumulative persisting annual savings
17 for the year ending December 31, 2023;

18 (7) 2.8% deemed cumulative persisting annual savings
19 for the year ending December 31, 2024;

20 (8) 2.5% deemed cumulative persisting annual savings
21 for the year ending December 31, 2025;

22 (9) 2.3% deemed cumulative persisting annual savings
23 for the year ending December 31, 2026;

24 (10) 2.1% deemed cumulative persisting annual savings
25 for the year ending December 31, 2027;

26 (11) 1.8% deemed cumulative persisting annual savings

1 for the year ending December 31, 2028;

2 (12) 1.7% deemed cumulative persisting annual savings
3 for the year ending December 31, 2029; and

4 (13) 1.5% deemed cumulative persisting annual savings
5 for the year ending December 31, 2030.

6 (b-15) Beginning in 2018, electric utilities subject to
7 this Section that serve less than 3,000,000 retail customers
8 but more than 500,000 retail customers in the State shall
9 achieve the following cumulative persisting annual savings
10 goals, as modified by subsection (b-20) and subsection (f) of
11 this Section and as compared to the deemed baseline as reduced
12 by the number of MWhs equal to the sum of the annual
13 consumption of customers that are exempt from subsections (a)
14 through (j) of this Section under subsection (l) of this
15 Section as averaged across the calendar years 2014, 2015, and
16 2016, through the implementation of energy efficiency measures
17 during the applicable year and in prior years, but no earlier
18 than January 1, 2012:

19 (1) 7.4% cumulative persisting annual savings for the
20 year ending December 31, 2018;

21 (2) 8.2% cumulative persisting annual savings for the
22 year ending December 31, 2019;

23 (3) 9.0% cumulative persisting annual savings for the
24 year ending December 31, 2020;

25 (4) 9.8% cumulative persisting annual savings for the
26 year ending December 31, 2021;

1 (5) 10.6% cumulative persisting annual savings for the
2 year ending December 31, 2022;

3 (6) 11.4% cumulative persisting annual savings for the
4 year ending December 31, 2023;

5 (7) 12.2% cumulative persisting annual savings for the
6 year ending December 31, 2024;

7 (8) 13% cumulative persisting annual savings for the
8 year ending December 31, 2025;

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

11 (10) 14.2% cumulative persisting annual savings for
12 the year ending December 31, 2027;

13 (11) 14.8% cumulative persisting annual savings for
14 the year ending December 31, 2028;

15 (12) 15.4% cumulative persisting annual savings for
16 the year ending December 31, 2029; and

17 (13) 16% cumulative persisting annual savings for the
18 year ending December 31, 2030.

19 The difference between the cumulative persisting annual
20 savings goal for the applicable calendar year and the
21 cumulative persisting annual savings goal for the immediately
22 preceding calendar year is 0.8% for the period of January 1,
23 2018 through December 31, 2025 and 0.6% for the period of
24 January 1, 2026 through December 31, 2030.

25 (b-20) Each electric utility subject to this Section may
26 include cost-effective voltage optimization measures in its

1 plans submitted under subsections (f) and (g) of this Section,
2 and the costs incurred by a utility to implement the measures
3 under a Commission-approved plan shall be recovered under the
4 provisions of Article IX or Section 16-108.5 of this Act. For
5 purposes of this Section, the measure life of voltage
6 optimization measures shall be 15 years. The measure life
7 period is independent of the depreciation rate of the voltage
8 optimization assets deployed.

9 Within 270 days after June 1, 2017 (the effective date of
10 Public Act 99-906), an electric utility that serves less than
11 3,000,000 retail customers but more than 500,000 retail
12 customers in the State shall file a plan with the Commission
13 that identifies the cost-effective voltage optimization
14 investment the electric utility plans to undertake through
15 December 31, 2024. The Commission, after notice and hearing,
16 shall approve or approve with modification the plan within 120
17 days after the plan's filing and, in the order approving or
18 approving with modification the plan, the Commission shall
19 adjust the applicable cumulative persisting annual savings
20 goals set forth in subsection (b-15) to reflect any amount of
21 cost-effective energy savings approved by the Commission that
22 is greater than or less than the following cumulative
23 persisting annual savings values attributable to voltage
24 optimization for the applicable year:

- 25 (1) 0.0% of cumulative persisting annual savings for
26 the year ending December 31, 2018;

1 (2) 0.17% of cumulative persisting annual savings for
2 the year ending December 31, 2019;

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

5 (4) 0.33% of cumulative persisting annual savings for
6 the year ending December 31, 2021;

7 (5) 0.5% of cumulative persisting annual savings for
8 the year ending December 31, 2022;

9 (6) 0.67% of cumulative persisting annual savings for
10 the year ending December 31, 2023;

11 (7) 0.83% of cumulative persisting annual savings for
12 the year ending December 31, 2024; and

13 (8) 1.0% of cumulative persisting annual savings for
14 the year ending December 31, 2025.

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

1 subsection (b-25).

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

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

1 that educate about, incentivize, encourage, or otherwise
2 support the adoption of electric vehicles by retail customers
3 of all customer classes.

4 (c) Electric utilities shall be responsible for overseeing
5 the design, development, and filing of energy efficiency plans
6 with the Commission and may, as part of that implementation,
7 outsource various aspects of program development and
8 implementation. A minimum of 10%, for electric utilities that
9 serve more than 3,000,000 retail customers in the State, and a
10 minimum of 7%, for electric utilities that serve less than
11 3,000,000 retail customers but more than 500,000 retail
12 customers in the State, of the utility's entire portfolio
13 funding level for a given year shall be used to procure
14 cost-effective energy efficiency measures from units of local
15 government, municipal corporations, school districts, public
16 housing, and community college districts, provided that a
17 minimum percentage of available funds shall be used to procure
18 energy efficiency from public housing, which percentage shall
19 be equal to public housing's share of public building energy
20 consumption.

21 The utilities shall also implement energy efficiency
22 measures targeted at low-income households, which, for
23 purposes of this Section, shall be defined as households at or
24 below 80% of area median income, and expenditures to implement
25 the measures shall be no less than \$25,000,000 per year for
26 electric utilities that serve more than 3,000,000 retail

1 customers in the State and no less than \$8,350,000 per year for
2 electric utilities that serve less than 3,000,000 retail
3 customers but more than 500,000 retail customers in the State.

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

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

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

25 The electric utilities shall also convene a low-income
26 energy efficiency advisory committee to assist in the design

1 and evaluation of the low-income energy efficiency programs.
2 The committee shall be comprised of the electric utilities
3 subject to the requirements of this Section, the gas utilities
4 subject to the requirements of Section 8-104 of this Act, the
5 utilities' low-income energy efficiency implementation
6 contractors, and representatives of community-based
7 organizations.

8 (d) Notwithstanding any other provision of law to the
9 contrary, a utility providing approved energy efficiency
10 measures and, if applicable, demand-response measures in the
11 State shall be permitted to recover all reasonable and
12 prudently incurred costs of those measures from all retail
13 customers, except as provided in subsection (1) of this
14 Section, as follows, provided that nothing in this subsection

15 (d) permits the double recovery of such costs from customers:

16 (1) The utility may recover its costs through an
17 automatic adjustment clause tariff filed with and approved
18 by the Commission. The tariff shall be established outside
19 the context of a general rate case. Each year the
20 Commission shall initiate a review to reconcile any amounts
21 collected with the actual costs and to determine the
22 required adjustment to the annual tariff factor to match
23 annual expenditures. To enable the financing of the
24 incremental capital expenditures, including regulatory
25 assets, for electric utilities that serve less than
26 3,000,000 retail customers but more than 500,000 retail

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

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

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

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

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

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

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

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

11 (ii) 580 basis points.

12 For electric utilities that serve less than
13 3,000,000 retail customers but more than 500,000
14 retail customers in the State, for each rate year
15 commencing after November 30, 2019, the cost of equity
16 shall be calculated as the sum of the following: (i)
17 the average for the applicable calendar year of the
18 monthly average yields of 30-year U.S. Treasury bonds
19 published by the Board of Governors of the Federal
20 Reserve System in its weekly H.15 Statistical Release
21 or successor publication; and (ii) 680 basis points;
22 however, if the cost of equity as calculated under this
23 subparagraph (C) of this paragraph (2) for each rate
24 year commencing after November 30, 2019, for electric
25 utilities that serve less than 3,000,000 retail
26 customers but more than 500,000 retail customers in

1 this State is greater than the national average cost of
2 equity for the rate year by 50 basis points or more,
3 then the Illinois Commerce Commission shall include a
4 cost of equity at a rate equal to the national average
5 cost of equity as calculated under this subparagraph
6 (C) of this paragraph (2) plus 50 basis points. For
7 purposes of this subparagraph (C) of this paragraph
8 (2), the national average cost of equity for a rate
9 year shall be the simple average of the cost of equity
10 approved in each order of a state regulatory
11 commission, other than the Commission, issued during
12 that rate year that is applicable to retail electric
13 service provided by an investor-owned public utility
14 company operating in the United States. No order shall
15 be excluded from the national average cost of equity
16 calculated under this subparagraph (C) of this
17 paragraph (2) on the grounds that it is subject to
18 rehearing or appeal. In the hearing during the first
19 rate year commencing after November 30, 2019, the
20 Commission shall set the cost of equity using the
21 method applicable to rate years commencing prior to
22 December 1, 2019. In the hearings in rate years
23 subsequent to such first rate year, the Commission
24 shall set the cost of equity using the method
25 applicable to rate years commencing after November 30,
26 2019, including the reconciliation of the first rate

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

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

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

24 (i) recovery of incentive compensation expense
25 that is based on the achievement of operational
26 metrics, including metrics related to budget

1 controls, outage duration and frequency, safety,
2 customer service, efficiency and productivity, and
3 environmental compliance; however, this protocol
4 shall not apply if such expense related to costs
5 incurred under this Section is recovered under
6 Article IX or Section 16-108.5 of this Act;
7 incentive compensation expense that is based on
8 net income or an affiliate's earnings per share
9 shall not be recoverable under the energy
10 efficiency formula rate;

11 (ii) recovery of pension and other
12 post-employment benefits expense, provided that
13 such costs are supported by an actuarial study;
14 however, this protocol shall not apply if such
15 expense related to costs incurred under this
16 Section is recovered under Article IX or Section
17 16-108.5 of this Act;

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

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

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

26 (E) Provide for an annual reconciliation, as

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

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

25 The Commission shall review the proposed tariff in
26 conjunction with its review of a proposed multi-year plan,

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

10 The tariff's rate design and cost allocation across
11 customer classes shall be consistent with the utility's
12 automatic adjustment clause tariff in effect on June 1,
13 2017 (the effective date of Public Act 99-906); however,
14 the Commission may revise the tariff's rate design and cost
15 allocation in subsequent proceedings under paragraph (3)
16 of this subsection (d).

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

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

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

13 (A) The inputs to the energy efficiency formula
14 rate for the applicable rate year shall be based on the
15 projected costs to be incurred by the utility during
16 the rate year under the utility's multi-year plan
17 approved under subsections (f) and (g) of this Section,
18 including, but not limited to, projected capital
19 investment costs and projected regulatory asset
20 balances with correspondingly updated depreciation and
21 amortization reserves and expense. The filing shall
22 also include a reconciliation of the energy efficiency
23 revenue requirement that was in effect for the prior
24 rate year (as set by the cost inputs for the prior rate
25 year) with the actual revenue requirement for the prior
26 rate year (determined using a year-end rate base) that

1 uses amounts reflected in the applicable FERC Form 1
2 that reports the actual costs for the prior rate year.
3 Any over-collection or under-collection indicated by
4 such reconciliation shall be reflected as a credit
5 against, or recovered as an additional charge to,
6 respectively, with interest calculated at a rate equal
7 to the utility's weighted average cost of capital
8 approved by the Commission for the prior rate year, the
9 charges for the applicable rate year. Such
10 over-collection or under-collection shall be adjusted
11 to remove any deferred taxes related to the
12 reconciliation, for purposes of calculating interest
13 at an annual rate of return equal to the utility's
14 weighted average cost of capital approved by the
15 Commission for the prior rate year, including a revenue
16 conversion factor calculated to recover or refund all
17 additional income taxes that may be payable or
18 receivable as a result of that return. Each
19 reconciliation shall be certified by the participating
20 utility in the same manner that FERC Form 1 is
21 certified. The filing shall also include the charge or
22 credit, if any, resulting from the calculation
23 required by subparagraph (E) of paragraph (2) of this
24 subsection (d).

25 Notwithstanding any other provision of law to the
26 contrary, the intent of the reconciliation is to

1 ultimately reconcile both the revenue requirement
2 reflected in rates for each calendar year, beginning
3 with the calendar year in which the utility files its
4 energy efficiency formula rate tariff under paragraph
5 (2) of this subsection (d), with what the revenue
6 requirement determined using a year-end rate base for
7 the applicable calendar year would have been had the
8 actual cost information for the applicable calendar
9 year been available at the filing date.

10 For purposes of this Section, "FERC Form 1" means
11 the Annual Report of Major Electric Utilities,
12 Licensees and Others that electric utilities are
13 required to file with the Federal Energy Regulatory
14 Commission under the Federal Power Act, Sections 3,
15 4(a), 304 and 209, modified as necessary to be
16 consistent with 83 Ill. Admin. Code Part 415 as of May
17 1, 2011. Nothing in this Section is intended to allow
18 costs that are not otherwise recoverable to be
19 recoverable by virtue of inclusion in FERC Form 1.

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

26 (C) The filing shall include relevant and

1 necessary data and documentation for the applicable
2 rate year. Normalization adjustments shall not be
3 required.

4 Within 45 days after the utility files its annual
5 update of cost inputs to the energy efficiency formula
6 rate, the Commission shall with reasonable notice,
7 initiate a proceeding concerning whether the projected
8 costs to be incurred by the utility and recovered during
9 the applicable rate year, and that are reflected in the
10 inputs to the energy efficiency formula rate, are
11 consistent with the utility's approved multi-year plan
12 under subsections (f) and (g) of this Section and whether
13 the costs incurred by the utility during the prior rate
14 year were prudent and reasonable. The Commission shall also
15 have the authority to investigate the information and data
16 described in paragraph (9) of subsection (g) of this
17 Section, including the proposed adjustment to the
18 utility's return on equity component of its weighted
19 average cost of capital. During the course of the
20 proceeding, each objection shall be stated with
21 particularity and evidence provided in support thereof,
22 after which the utility shall have the opportunity to rebut
23 the evidence. Discovery shall be allowed consistent with
24 the Commission's Rules of Practice, which Rules of Practice
25 shall be enforced by the Commission or the assigned
26 administrative law judge. The Commission shall apply the

1 same evidentiary standards, including, but not limited to,
2 those concerning the prudence and reasonableness of the
3 costs incurred by the utility, during the proceeding as it
4 would apply in a proceeding to review a filing for a
5 general increase in rates under Article IX of this Act. The
6 Commission shall not, however, have the authority in a
7 proceeding under this paragraph (3) to consider or order
8 any changes to the structure or protocols of the energy
9 efficiency formula rate approved under paragraph (2) of
10 this subsection (d). In a proceeding under this paragraph
11 (3), the Commission shall enter its order no later than the
12 earlier of 195 days after the utility's filing of its
13 annual update of cost inputs to the energy efficiency
14 formula rate or December 15. The utility's proposed return
15 on equity calculation, as described in paragraphs (7)
16 through (9) of subsection (g) of this Section, shall be
17 deemed the final, approved calculation on December 15 of
18 the year in which it is filed unless the Commission enters
19 an order on or before December 15, after notice and
20 hearing, that modifies such calculation consistent with
21 this Section. The Commission's determinations of the
22 prudence and reasonableness of the costs incurred, and
23 determination of such return on equity calculation, for the
24 applicable calendar year shall be final upon entry of the
25 Commission's order and shall not be subject to reopening,
26 reexamination, or collateral attack in any other

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

6 (e) Beginning on June 1, 2017 (the effective date of Public
7 Act 99-906), a utility subject to the requirements of this
8 Section may elect to defer, as a regulatory asset, up to the
9 full amount of its expenditures incurred under this Section for
10 each annual period, including, but not limited to, any
11 expenditures incurred above the funding level set by subsection
12 (f) of this Section for a given year. The total expenditures
13 deferred as a regulatory asset in a given year shall be
14 amortized and recovered over a period that is equal to the
15 weighted average of the energy efficiency measure lives
16 implemented for that year that are reflected in the regulatory
17 asset. The unamortized balance shall be recognized as of
18 December 31 for a given year. The utility shall also earn a
19 return on the total of the unamortized balances of all of the
20 energy efficiency regulatory assets, less any deferred taxes
21 related to those unamortized balances, at an annual rate equal
22 to the utility's weighted average cost of capital that
23 includes, based on a year-end capital structure, the utility's
24 actual cost of debt for the applicable calendar year and a cost
25 of equity, which shall be calculated in accordance with the
26 calculations set forth in subparagraph (C) of paragraph (2) of

1 ~~subsection (d) of this Section as the sum of the (i) the~~
2 ~~average for the applicable calendar year of the monthly average~~
3 ~~yields of 30-year U.S. Treasury bonds published by the Board of~~
4 ~~Governors of the Federal Reserve System in its weekly H.15~~
5 ~~Statistical Release or successor publication; and (ii) 500~~
6 ~~basis points,~~ including a revenue conversion factor calculated
7 to recover or refund all additional income taxes that may be
8 payable or receivable as a result of that return. Capital
9 investment costs shall be depreciated and recovered over their
10 useful lives consistent with generally accepted accounting
11 principles. The weighted average cost of capital shall be
12 applied to the capital investment cost balance, less any
13 accumulated depreciation and accumulated deferred income
14 taxes, as of December 31 for a given year.

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

1 impaired, or reduced.

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

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

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

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

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

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

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

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

1 Public Act 99-906). For those plans commencing after December
2 31, 2021, the Commission shall seek public comment on the
3 utility's plan and shall issue an order approving or
4 disapproving each plan within 6 months after its submission. If
5 the Commission disapproves a plan, the Commission shall, within
6 30 days, describe in detail the reasons for the disapproval and
7 describe a path by which the utility may file a revised draft
8 of the plan to address the Commission's concerns
9 satisfactorily. If the utility does not refile with the
10 Commission within 60 days, the utility shall be subject to
11 penalties at a rate of \$100,000 per day until the plan is
12 filed. This process shall continue, and penalties shall accrue,
13 until the utility has successfully filed a portfolio of energy
14 efficiency and demand-response measures. Penalties shall be
15 deposited into the Energy Efficiency Trust Fund.

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

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

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

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

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

14 (A) beginning with the year commencing January 1,
15 2019, electric utilities that serve more than
16 3,000,000 retail customers in the State shall fund
17 third-party energy efficiency programs in an amount
18 that is no less than \$25,000,000 per year, and electric
19 utilities that serve less than 3,000,000 retail
20 customers but more than 500,000 retail customers in the
21 State shall fund third-party energy efficiency
22 programs in an amount that is no less than \$8,350,000
23 per year;

24 (B) during 2018, the utility shall conduct a
25 solicitation process for purposes of requesting
26 proposals from third-party vendors for those

1 third-party energy efficiency programs to be offered
2 during one or more of the years commencing January 1,
3 2019, January 1, 2020, and January 1, 2021; for those
4 multi-year plans commencing on January 1, 2022 and
5 January 1, 2026, the utility shall conduct a
6 solicitation process during 2021 and 2025,
7 respectively, for purposes of requesting proposals
8 from third-party vendors for those third-party energy
9 efficiency programs to be offered during one or more
10 years of the respective multi-year plan period; for
11 each solicitation process, the utility shall identify
12 the sector, technology, or geographical area for which
13 it is seeking requests for proposals;

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

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

26 The electric utility shall recover all costs

1 associated with Commission-approved, third-party
2 administered programs regardless of the success of those
3 programs.

4 (4.5) Implement cost-effective demand-response
5 measures to reduce peak demand by 0.1% over the prior year
6 for eligible retail customers, as defined in Section
7 16-111.5 of this Act, and for customers that elect hourly
8 service from the utility pursuant to Section 16-107 of this
9 Act, provided those customers have not been declared
10 competitive. This requirement continues until December 31,
11 2026.

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

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

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

14 (7) For electric utilities that serve more than
15 3,000,000 retail customers in the State:

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

20 (i) If the independent evaluator determines
21 that the utility achieved a cumulative persisting
22 annual savings that is less than the applicable
23 annual incremental goal, then the return on equity
24 component shall be reduced by a maximum of 200
25 basis points in the event that the utility achieved
26 no more than 75% of such goal. If the utility

1 achieved more than 75% of the applicable annual
2 incremental goal but less than 100% of such goal,
3 then the return on equity component shall be
4 reduced by 8 basis points for each percent by which
5 the utility failed to achieve the goal.

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

23 (aa) the calculation for determining
24 achievement that is at least 125% of the
25 applicable annual incremental goal shall use
26 the unreduced applicable annual incremental

1 goal to set the value; and

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

14 (B) For the period January 1, 2026 through December
15 31, 2030, provide for an adjustment to the return on
16 equity component of the utility's weighted average
17 cost of capital calculated under subsection (d) of this
18 Section:

19 (i) If the independent evaluator determines
20 that the utility achieved a cumulative persisting
21 annual savings that is less than the applicable
22 annual incremental goal, then the return on equity
23 component shall be reduced by a maximum of 200
24 basis points in the event that the utility achieved
25 no more than 66% of such goal. If the utility
26 achieved more than 66% of the applicable annual

1 incremental goal but less than 100% of such goal,
2 then the return on equity component shall be
3 reduced by 6 basis points for each percent by which
4 the utility failed to achieve the goal.

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

22 (aa) the calculation for determining
23 achievement that is at least 134% of the
24 applicable annual incremental goal shall use
25 the unreduced applicable annual incremental
26 goal to set the value; and

1 (bb) the calculation for determining
2 achievement that is less than 134% but more
3 than 100% of the applicable annual incremental
4 goal shall use the reduced applicable annual
5 incremental goal to set the value for 100%
6 achievement of the goal and shall use the
7 unreduced goal to set the value for 134%
8 achievement. The 6 basis point value shall also
9 be modified, as necessary, so that the 200
10 basis points are evenly apportioned among each
11 percentage point value between 100% and 134%
12 achievement.

13 (7.5) For purposes of this Section, the term
14 "applicable annual incremental goal" means the difference
15 between the cumulative persisting annual savings goal for
16 the calendar year that is the subject of the independent
17 evaluator's determination and the cumulative persisting
18 annual savings goal for the immediately preceding calendar
19 year, as such goals are defined in subsections (b-5) and
20 (b-15) of this Section and as these goals may have been
21 modified as provided for under subsection (b-20) and
22 paragraphs (1) through (3) of subsection (f) of this
23 Section. Under subsections (b), (b-5), (b-10), and (b-15)
24 of this Section, a utility must first replace energy
25 savings from measures that have reached the end of their
26 measure lives and would otherwise have to be replaced to

1 meet the applicable savings goals identified in subsection
2 (b-5) or (b-15) of this Section before any progress towards
3 achievement of its applicable annual incremental goal may
4 be counted. Notwithstanding anything else set forth in this
5 Section, the difference between the actual annual
6 incremental savings achieved in any given year, including
7 the replacement of energy savings from measures that have
8 expired, and the applicable annual incremental goal shall
9 not affect adjustments to the return on equity for
10 subsequent calendar years under this subsection (g).

11 (8) For electric utilities that serve less than
12 3,000,000 retail customers but more than 500,000 retail
13 customers in the State:

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

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

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

26 (iii) The return on equity component shall not

1 be increased or decreased if the annual
2 incremental savings as determined by the
3 independent evaluator is greater than 84.4% of the
4 applicable annual incremental goal and less than
5 100% of the applicable annual incremental goal.

6 (iv) The return on equity component shall not
7 be increased or decreased by an amount greater than
8 200 basis points pursuant to this subparagraph
9 (A).

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

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

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

22 (iii) The return on equity component shall not
23 be increased or decreased by an amount greater than
24 200 basis points pursuant to this subparagraph
25 (B).

26 (C) If the applicable annual incremental goal was

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

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

10 (ii) For the period through December 31, 2025,
11 the calculation for determining achievement that
12 is less than 125% but more than 100% of the
13 applicable annual incremental goal shall use the
14 reduced applicable annual incremental goal to set
15 the value for 100% achievement of the goal and
16 shall use the unreduced goal to set the value for
17 125% achievement. The 8 basis point value shall
18 also be modified, as necessary, so that the 200
19 basis points are evenly apportioned among each
20 percentage point value between 100% and 125%
21 achievement.

22 (iii) For the period of January 1, 2026 through
23 December 31, 2030, the calculation for determining
24 achievement that is less than 134% but more than
25 100% of the applicable annual incremental goal
26 shall use the reduced applicable annual

1 incremental goal to set the value for 100%
2 achievement of the goal and shall use the unreduced
3 goal to set the value for 125% achievement. The 6
4 basis point value shall also be modified, as
5 necessary, so that the 200 basis points are evenly
6 apportioned among each percentage point value
7 between 100% and 134% achievement.

8 (8.5) Electric utilities that serve less than
9 3,000,000 retail customers but more than 500,000 retail
10 customers in this State may identify, at the electric
11 utility's sole discretion, cost-effective measures that
12 educate about, incentivize, encourage, or otherwise
13 support the use of electricity to power, in whole or in
14 part, vehicles, including, but not limited to, cars,
15 trucks, buses, trains, trolleys, boats, on-road or
16 off-road vehicles, or other equipment or methods of
17 transporting goods or people. Such measures may include,
18 but are not limited to, measures that educate about,
19 incentivize, encourage, or otherwise support the adoption
20 of electric vehicles by retail customers of all rate
21 classes.

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

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

19 For those utilities that must submit the informational
20 filing, the Commission may, on its own motion or by
21 petition, initiate an investigation of such filing,
22 provided, however, that the utility's proposed return on
23 equity calculation shall be deemed the final, approved
24 calculation on December 15 of the year in which it is filed
25 unless the Commission enters an order on or before December
26 15, after notice and hearing, that modifies such

1 calculation consistent with this Section.

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

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

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

18 (j) The independent evaluator shall follow the guidelines
19 and use the savings set forth in Commission-approved energy
20 efficiency policy manuals and technical reference manuals, as
21 each may be updated from time to time. Until such time as
22 measure life values for energy efficiency measures implemented
23 for low-income households under subsection (c) of this Section
24 are incorporated into such Commission-approved manuals, the
25 low-income measures shall have the same measure life values
26 that are established for same measures implemented in

1 households that are not low-income households.

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

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

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

22 (B) the evaluation shall use a heat rate of fossil
23 fuel electric generating units of 7,939 Btu per
24 kilowatt hour, adjusted each year starting with the
25 year in which this amendatory Act of the 101st General
26 Assembly takes effect to reflect the annual increase of

1 renewable resource procurement as set forth in
2 subsection (c) of Section 1-75 of the Illinois Power
3 Agency Act;

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

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

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

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

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

26 (B) the evaluation shall use a value of 11,500

1 vehicle miles traveled for annual vehicle operation;

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

5 (D) the evaluation shall use a conversion factor of
6 120,429 Btus per gallon of fossil fuel used for vehicle
7 operation;

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

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

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

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

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

1 updated from time to time.

2 (k) Notwithstanding any provision of law to the contrary,
3 an electric utility subject to the requirements of this Section
4 may file a tariff cancelling an automatic adjustment clause
5 tariff in effect under this Section or Section 8-103, which
6 shall take effect no later than one business day after the date
7 such tariff is filed. Thereafter, the utility shall be
8 authorized to defer and recover its expenditures incurred under
9 this Section through a new tariff authorized under subsection
10 (d) of this Section or in the utility's next rate case under
11 Article IX or Section 16-108.5 of this Act, with interest at an
12 annual rate equal to the utility's weighted average cost of
13 capital as approved by the Commission in such case. If the
14 utility elects to file a new tariff under subsection (d) of
15 this Section, the utility may file the tariff within 10 days
16 after June 1, 2017 (the effective date of Public Act 99-906),
17 and the cost inputs to such tariff shall be based on the
18 projected costs to be incurred by the utility during the
19 calendar year in which the new tariff is filed and that were
20 not recovered under the tariff that was cancelled as provided
21 for in this subsection. Such costs shall include those incurred
22 or to be incurred by the utility under its multi-year plan
23 approved under subsections (f) and (g) of this Section,
24 including, but not limited to, projected capital investment
25 costs and projected regulatory asset balances with
26 correspondingly updated depreciation and amortization reserves

1 and expense. The Commission shall, after notice and hearing,
2 approve, or approve with modification, such tariff and cost
3 inputs no later than 75 days after the utility filed the
4 tariff, provided that such approval, or approval with
5 modification, shall be consistent with the provisions of this
6 Section to the extent they do not conflict with this subsection
7 (k). The tariff approved by the Commission shall take effect no
8 later than 5 days after the Commission enters its order
9 approving the tariff.

10 No later than 60 days after the effective date of the
11 tariff cancelling the utility's automatic adjustment clause
12 tariff, the utility shall file a reconciliation that reconciles
13 the moneys collected under its automatic adjustment clause
14 tariff with the costs incurred during the period beginning June
15 1, 2016 and ending on the date that the electric utility's
16 automatic adjustment clause tariff was cancelled. In the event
17 the reconciliation reflects an under-collection, the utility
18 shall recover the costs as specified in this subsection (k). If
19 the reconciliation reflects an over-collection, the utility
20 shall apply the amount of such over-collection as a one-time
21 credit to retail customers' bills.

22 (l) For the calendar years covered by a multi-year plan
23 commencing after December 31, 2017, subsections (a) through (j)
24 of this Section do not apply to any retail customers of an
25 electric utility that serves more than 3,000,000 retail
26 customers in the State and whose total highest 30 minute demand

1 was more than 10,000 kilowatts, or any retail customers of an
2 electric utility that serves less than 3,000,000 retail
3 customers but more than 500,000 retail customers in the State
4 and whose total highest 15 minute demand was more than 10,000
5 kilowatts. For purposes of this subsection (1), "retail
6 customer" has the meaning set forth in Section 16-102 of this
7 Act. A determination of whether this subsection is applicable
8 to a customer shall be made for each multi-year plan beginning
9 after December 31, 2017. The criteria for determining whether
10 this subsection (1) is applicable to a retail customer shall be
11 based on the 12 consecutive billing periods prior to the start
12 of the first year of each such multi-year plan.

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

21 (1) 3.5% for each of the 4 years beginning January 1,
22 2018,

23 (2) 3.75% for each of the 4 years beginning January 1,
24 2022, and

25 (3) 4% for each of the 5 years beginning January 1,
26 2026,

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

19 (n) Starting on the effective date of this amendatory Act
20 of the 101st General Assembly, electric utilities that serve
21 less than 3,000,000 retail customers but more than 500,000
22 retail customers in this State may administer programs and
23 implement cost-effective measures that educate about,
24 incentivize, encourage, or otherwise support the use of
25 electricity to power, in whole or in part, vehicles, including,
26 but not limited to, cars, trucks, buses, trains, trolleys,

1 boats, on-road or off-road vehicles, or other equipment or
2 methods of transporting goods or people. Such programs and
3 measures may be implemented as part of a plan approved pursuant
4 to subsection (f) of this Section and may include, but are not
5 limited to, measures that educate about, incentivize,
6 encourage, or otherwise support the adoption of electric
7 vehicles by retail customers of all customer classes. Programs
8 and measures authorized by this subsection (n) and identified
9 pursuant to paragraph (8.5) of subsection (g) shall not be
10 prohibited by the Commission as promotional practices under any
11 rules or policies of the Commission, including, but not limited
12 to, 83 Ill. Admin. Code Part 275.

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

14 (220 ILCS 5/8-218 new)

15 Sec. 8-218. Electric photovoltaic generating facilities.

16 (a) The General Assembly finds and declares that the
17 citizens and businesses of the State of Illinois would be
18 well-served by the development of photovoltaic electricity
19 production facilities in this State, which would both bring
20 economic benefits and environmental benefits to the State and
21 further expand access to renewable energy resources at an
22 affordable cost to Illinois residents, particularly in those
23 areas of the State that have been significantly and adversely
24 affected by the retirement of coal-fired electric generating
25 plants. To that end, the General Assembly seeks to encourage

1 further development of photovoltaic electric production
2 facilities of all scales in an efficient and cost-effective
3 manner. Accordingly, the General Assembly finds that,
4 notwithstanding other provisions of this Act to the contrary,
5 it would be both prudent and reasonable for electric utilities
6 in this State to plan for, construct, install, control, own,
7 manage, or operate photovoltaic electricity production
8 facilities pursuant to the provisions of this Section.

9 (b) An electric utility that serves less than 3,000,000
10 retail customers but more than 500,000 customers in this State,
11 may plan for, construct, install, control, own, manage, or
12 operate photovoltaic electricity production facilities and any
13 energy storage facilities as authorized under Section
14 16-108.20 of this Act that are planned for, constructed,
15 installed, controlled, owned, managed, or operated in
16 connection with photovoltaic electricity production facilities
17 authorized under this Section without obtaining a certificate
18 of public convenience and necessity pursuant to Section 8-406
19 of this Act, subject to the following terms and conditions:

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

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

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

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

1 renewable energy credits associated with the photovoltaic
2 electricity production facilities shall be retired on
3 behalf of the electric utility's distribution customers
4 and may not be sold or used for any other purposes by the
5 electric utility other than satisfying the electric
6 utility's requirements under subsection (c) of Section
7 1-75 of the Illinois Power Agency Act; and

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

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

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

1 subparagraph (E) of paragraph (1) of subsection (c) of Section
2 1-75 of the Illinois Power Agency Act.

3 (220 ILCS 5/16-102)

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

7 "Alternative retail electric supplier" means every person,
8 cooperative, corporation, municipal corporation, company,
9 association, joint stock company or association, firm,
10 partnership, individual, or other entity, their lessees,
11 trustees, or receivers appointed by any court whatsoever, that
12 offers electric power or energy for sale, lease or in exchange
13 for other value received to one or more retail customers, or
14 that engages in the delivery or furnishing of electric power or
15 energy to such retail customers, and shall include, without
16 limitation, resellers, aggregators and power marketers, but
17 shall not include (i) electric utilities (or any agent of the
18 electric utility to the extent the electric utility provides
19 tariffed services to retail customers through that agent), (ii)
20 any electric cooperative or municipal system as defined in
21 Section 17-100 to the extent that the electric cooperative or
22 municipal system is serving retail customers within any area in
23 which it is or would be entitled to provide service under the
24 law in effect immediately prior to the effective date of this
25 amendatory Act of 1997, (iii) a public utility that is owned

1 and operated by any public institution of higher education of
2 this State, or a public utility that is owned by such public
3 institution of higher education and operated by any of its
4 lessees or operating agents, within any area in which it is or
5 would be entitled to provide service under the law in effect
6 immediately prior to the effective date of this amendatory Act
7 of 1997, (iv) a retail customer to the extent that customer
8 obtains its electric power and energy from that customer's own
9 cogeneration or self-generation facilities, (v) an entity that
10 owns, operates, sells, or arranges for the installation of a
11 customer's own cogeneration or self-generation facilities, but
12 only to the extent the entity is engaged in owning, selling or
13 arranging for the installation of such facility, or operating
14 the facility on behalf of such customer, provided however that
15 any such third party owner or operator of a facility built
16 after January 1, 1999, complies with the labor provisions of
17 Section 16-128(a) as though such third party were an
18 alternative retail electric supplier, or (vi) an industrial or
19 manufacturing customer that owns its own distribution
20 facilities, to the extent that the customer provides service
21 from that distribution system to a third-party contractor
22 located on the customer's premises that is integrally and
23 predominantly engaged in the customer's industrial or
24 manufacturing process; provided, that if the industrial or
25 manufacturing customer has elected delivery services, the
26 customer shall pay transition charges applicable to the

1 electric power and energy consumed by the third-party
2 contractor unless such charges are otherwise paid by the third
3 party contractor, which shall be calculated based on the usage
4 of, and the base rates or the contract rates applicable to, the
5 third-party contractor in accordance with Section 16-102.

6 An entity that furnishes the service of charging electric
7 vehicles does not and shall not be deemed to sell electricity
8 and is not and shall not be deemed an alternative retail
9 electric supplier, and is not subject to regulation as such
10 under this Act notwithstanding the basis on which the service
11 is provided or billed. If, however, the entity is otherwise
12 deemed an alternative retail electric supplier under this Act,
13 or is otherwise subject to regulation under this Act, then that
14 entity is not exempt from and remains subject to the otherwise
15 applicable provisions of this Act. The installation,
16 maintenance, and repair of an electric vehicle charging station
17 shall comply with the requirements of subsection (a) of Section
18 16-128 and Section 16-128A of this Act.

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

22 "Base rates" means the rates for those tariffed services
23 that the electric utility is required to offer pursuant to
24 subsection (a) of Section 16-103 and that were identified in a
25 rate order for collection of the electric utility's base rate
26 revenue requirement, excluding (i) separate automatic rate

1 adjustment riders then in effect, (ii) special or negotiated
2 contract rates, (iii) delivery services tariffs filed pursuant
3 to Section 16-108, (iv) real-time pricing, or (v) tariffs that
4 were in effect prior to October 1, 1996 and that based charges
5 for services on an index or average of other utilities'
6 charges, but including (vi) any subsequent redesign of such
7 rates for tariffed services that is authorized by the
8 Commission after notice and hearing.

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

15 "Contract service" means (1) services, including the
16 provision of electric power and energy or other services, that
17 are provided by mutual agreement between an electric utility
18 and a retail customer that is located in the electric utility's
19 service area, provided that, delivery services shall not be a
20 contract service until such services are declared competitive
21 pursuant to Section 16-113; and also means (2) the provision of
22 electric power and energy by an electric utility to retail
23 customers outside the electric utility's service area pursuant
24 to Section 16-116. Provided, however, contract service does not
25 include electric utility services provided pursuant to (i)
26 contracts that retail customers are required to execute as a

1 condition of receiving tariffed services, or (ii) special or
2 negotiated rate contracts for electric utility services that
3 were entered into between an electric utility and a retail
4 customer prior to the effective date of this amendatory Act of
5 1997 and filed with the Commission.

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

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

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

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

25 "Energy storage" or "storage" means any infrastructure,
26 facility, technology, or device used to store energy for use on

1 an electric distribution or transmission system and shall not
2 include or be considered energy generation.

3 "Mandatory transition period" means the period from the
4 effective date of this amendatory Act of 1997 through January
5 1, 2007.

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

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

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

1 tariffs that were on file with the Commission on the effective
2 date of this Act.

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

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

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

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

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

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

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

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

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

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

19 (A) for nonresidential retail customers, an amount
20 equal to the greater of (i) 0.5 cents per kilowatt-hour
21 during the period October 1, 1999 through December 31,
22 2004, 0.6 cents per kilowatt-hour in calendar year
23 2005, and 0.9 cents per kilowatt-hour in calendar year
24 2006, multiplied in each year by the usage identified
25 in paragraph (1), or (ii) an amount equal to the
26 following percentages of the amount produced by

1 applying the applicable base rates (adjusted as
2 described in subparagraph (1)(B)) or contract rate to
3 the usage identified in paragraph (1): 8% for the
4 period October 1, 1999 through December 31, 2002, 10%
5 in calendar years 2003 and 2004, 11% in calendar year
6 2005 and 12% in calendar year 2006; and

7 (B) for residential retail customers, an amount
8 equal to the following percentages of the amount
9 produced by applying the base rates in effect on
10 October 1, 1996 (adjusted as described in subparagraph
11 (1)(B)) to the usage identified in paragraph (1): (i)
12 6% from May 1, 2002 through December 31, 2002, (ii) 7%
13 in calendar years 2003 and 2004, (iii) 8% in calendar
14 year 2005, and (iv) 10% in calendar year 2006;

15 (5) divided by the usage of such customers identified
16 in paragraph (1),
17 provided that the transition charge shall never be less than
18 zero.

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

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

23 (220 ILCS 5/16-107.6)

24 Sec. 16-107.6. Distributed generation rebate.

25 (a) In this Section:

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

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

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

13 "Threshold date" means the date on which the load of an
14 electricity provider's net metering customers equals 5% of the
15 total peak demand supplied by that electricity provider during
16 the previous year, as specified under subsection (j) of Section
17 16-107.5 of this Act.

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

23 (1) has a nameplate generating capacity no greater than
24 2,000 kilowatts and is primarily used to offset that
25 customer's electricity load;

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

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

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

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

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

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

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

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

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

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

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

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

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

23 (B) Non-residential customers that are taking
24 service under a net metering program offered by an
25 electricity provider under the terms of Section
26 16-107.5 of this Act on the threshold date may apply

1 for a rebate as provided for in this Section. The value
2 of the rebate shall be the amount established by the
3 Commission and reflected in the utility's tariff
4 pursuant to subsection (e) of this Section.

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

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

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

26 (e) When the total generating capacity of the electricity

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

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

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

26 (h) An electric utility shall recover from its retail

1 customers all of the costs of the rebates made under a tariff
2 or tariffs placed into effect under this Section, including,
3 but not limited to, the value of the rebates and all costs
4 incurred by the utility to comply with and implement this
5 Section, consistent with the following provisions:

6 (1) The utility shall defer the full amount of its
7 costs incurred under this Section as a regulatory asset.
8 The total costs deferred as a regulatory asset shall be
9 amortized over a 15-year period. The unamortized balance
10 shall be recognized as of December 31 for a given year. The
11 utility shall also earn a return on the total of the
12 unamortized balance of the regulatory assets, less any
13 deferred taxes related to the unamortized balance, at an
14 annual rate equal to the utility's weighted average cost of
15 capital that includes, based on a year-end capital
16 structure, the utility's actual cost of debt for the
17 applicable calendar year and a cost of equity, which in all
18 rate years for electric utilities that serve more than
19 3,000,000 retail customers in this State, and in each rate
20 year commencing before December 1, 2019 for electric
21 utilities that serve less than 3,000,000 retail customers
22 but more than 500,000 retail customers in this State, shall
23 be calculated as the sum of (i) the average for the
24 applicable calendar year of the monthly average yields of
25 30-year U.S. Treasury bonds published by the Board of
26 Governors of the Federal Reserve System in its weekly H.15

1 Statistical Release or successor publication; and (ii) 580
2 basis points, including a revenue conversion factor
3 calculated to recover or refund all additional income taxes
4 that may be payable or receivable as a result of that
5 return. For electric utilities that serve less than
6 3,000,000 retail customers but more than 500,000 retail
7 customers in this State, for each rate year commencing
8 after November 30, 2019, the cost of equity shall be
9 calculated as the sum of the following: (i) the average for
10 the applicable calendar year of the monthly average yields
11 of 30-year U.S. Treasury bonds published by the Board of
12 Governors of the Federal Reserve System in its weekly H.15
13 Statistical Release or successor publication; and (ii) 680
14 basis points; however, if the cost of equity as calculated
15 under this paragraph (1) for each rate year commencing
16 after November 30, 2019, for electric utilities that serve
17 less than 3,000,000 retail customers but more than 500,000
18 retail customers in this State is greater than the national
19 average cost of equity for the rate year by 50 basis points
20 or more, then the Illinois Commerce Commission shall
21 include a cost of equity at a rate equal to the national
22 average cost of equity as calculated under this paragraph
23 (1) plus 50 basis points. For purposes of this paragraph
24 (1), the national average cost of equity for a rate year
25 shall be the simple average of the cost of equity approved
26 in each order of a state regulatory commission, other than

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

23 When an electric utility creates a regulatory asset
24 under the provisions of this Section, the costs are
25 recovered over a period during which customers also receive
26 a benefit, which is in the public interest. Accordingly, it

1 is the intent of the General Assembly that an electric
2 utility that elects to create a regulatory asset under the
3 provisions of this Section shall recover all of the
4 associated costs, including, but not limited to, its cost
5 of capital as set forth in this Section. After the
6 Commission has approved the prudence and reasonableness of
7 the costs that comprise the regulatory asset, the electric
8 utility shall be permitted to recover all such costs, and
9 the value and recoverability through rates of the
10 associated regulatory asset shall not be limited, altered,
11 impaired, or reduced. To enable the financing of the
12 incremental capital expenditures, including regulatory
13 assets, for electric utilities that serve less than
14 3,000,000 retail customers but more than 500,000 retail
15 customers in the State, the utility's actual year-end
16 capital structure that includes a common equity ratio,
17 excluding goodwill, of up to and including 50% of the total
18 capital structure shall be deemed reasonable and used to
19 set rates.

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

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

1 utility files its tariff.

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

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

13 (220 ILCS 5/16-108.5)

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

16 (a) (Blank).

17 (b) For purposes of this Section, "participating utility"
18 means an electric utility or a combination utility serving more
19 than 1,000,000 customers in Illinois that voluntarily elects
20 and commits to undertake (i) the infrastructure investment
21 program consisting of the commitments and obligations
22 described in this subsection (b) and (ii) the customer
23 assistance program consisting of the commitments and
24 obligations described in subsection (b-10) of this Section,
25 notwithstanding any other provisions of this Act and without

1 obtaining any approvals from the Commission or any other agency
2 other than as set forth in this Section, regardless of whether
3 any such approval would otherwise be required. "Combination
4 utility" means a utility that, as of January 1, 2011, provided
5 electric service to at least one million retail customers in
6 Illinois and gas service to at least 500,000 retail customers
7 in Illinois. A participating utility shall recover the
8 expenditures made under the infrastructure investment program
9 through the ratemaking process, including, but not limited to,
10 the performance-based formula rate and process set forth in
11 this Section.

12 During the infrastructure investment program's peak
13 program year, a participating utility other than a combination
14 utility shall create 2,000 full-time equivalent jobs in
15 Illinois, and a participating utility that is a combination
16 utility shall create 450 full-time equivalent jobs in Illinois
17 related to the provision of electric service. These jobs shall
18 include direct jobs, contractor positions, and induced jobs,
19 but shall not include any portion of a job commitment, not
20 specifically contingent on an amendatory Act of the 97th
21 General Assembly becoming law, between a participating utility
22 and a labor union that existed on December 30, 2011 (the
23 effective date of Public Act 97-646) and that has not yet been
24 fulfilled. A portion of the full-time equivalent jobs created
25 by each participating utility shall include incremental
26 personnel hired subsequent to December 30, 2011 (the effective

1 date of Public Act 97-646). For purposes of this Section, "peak
2 program year" means the consecutive 12-month period with the
3 highest number of full-time equivalent jobs that occurs between
4 the beginning of investment year 2 and the end of investment
5 year 4.

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

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

17 (A) over a 5-year period, invest an estimated
18 \$1,300,000,000 in electric system upgrades,
19 modernization projects, and training facilities,
20 including, but not limited to:

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

26 (ii) training facility construction or upgrade

1 projects totaling an estimated \$10,000,000,
2 provided that, at a minimum, one such facility
3 shall be located in a municipality having a
4 population of more than 2 million residents and one
5 such facility shall be located in a municipality
6 having a population of more than 150,000 residents
7 but fewer than 170,000 residents; any such new
8 facility located in a municipality having a
9 population of more than 2 million residents must be
10 designed for the purpose of obtaining, and the
11 owner of the facility shall apply for,
12 certification under the United States Green
13 Building Council's Leadership in Energy Efficiency
14 Design Green Building Rating System;

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

17 (iv) an estimated \$200,000,000 for reducing
18 the susceptibility of certain circuits to
19 storm-related damage, including, but not limited
20 to, high winds, thunderstorms, and ice storms;
21 improvements may include, but are not limited to,
22 overhead to underground conversion and other
23 engineered outcomes for circuits; the
24 participating utility shall prioritize the
25 selection of circuits based on each circuit's
26 historical susceptibility to storm-related damage

1 and the ability to provide the greatest customer
2 benefit upon completion of the improvements; to be
3 eligible for improvement, the participating
4 utility's ability to maintain proper tree
5 clearances surrounding the overhead circuit must
6 not have been impeded by third parties; and

7 (B) over a 10-year period, invest an estimated
8 \$1,300,000,000 to upgrade and modernize its
9 transmission and distribution infrastructure and in
10 Smart Grid electric system upgrades, including, but
11 not limited to:

12 (i) additional smart meters;

13 (ii) distribution automation;

14 (iii) associated cyber secure data
15 communication network; and

16 (iv) substation micro-processor relay
17 upgrades.

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

1 (A) over a 10-year period, invest an estimated
2 \$265,000,000 in electric system upgrades,
3 modernization projects, and training facilities,
4 including, but not limited to:

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

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

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

23 (B) over a 10-year period, invest an estimated
24 \$360,000,000 to upgrade and modernize its transmission
25 and distribution infrastructure and in Smart Grid
26 electric system upgrades, including, but not limited

1 to:

2 (i) additional smart meters;

3 (ii) distribution automation;

4 (iii) associated cyber secure data
5 communication network; and

6 (iv) substation micro-processor relay
7 upgrades.

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

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

26 Within 60 days after filing a tariff under subsection (c)

1 of this Section, a participating utility shall submit to the
2 Commission its plan, including scope, schedule, and staffing,
3 for satisfying its infrastructure investment program
4 commitments pursuant to this subsection (b). The submitted plan
5 shall include a schedule and staffing plan for the next
6 calendar year. The plan shall also include a plan for the
7 creation, operation, and administration of a Smart Grid test
8 bed as described in subsection (c) of Section 16-108.8. The
9 plan need not allocate the work equally over the respective
10 periods, but should allocate material increments throughout
11 such periods commensurate with the work to be undertaken. No
12 later than April 1 of each subsequent year, the utility shall
13 submit to the Commission a report that includes any updates to
14 the plan, a schedule for the next calendar year, the
15 expenditures made for the prior calendar year and cumulatively,
16 and the number of full-time equivalent jobs created for the
17 prior calendar year and cumulatively. If the utility is
18 materially deficient in satisfying a schedule or staffing plan,
19 then the report must also include a corrective action plan to
20 address the deficiency. The fact that the plan, implementation
21 of the plan, or a schedule changes shall not imply the
22 imprudence or unreasonableness of the infrastructure
23 investment program, plan, or schedule. Further, no later than
24 45 days following the last day of the first, second, and third
25 quarters of each year of the plan, a participating utility
26 shall submit to the Commission a verified quarterly report for

1 the prior quarter that includes (i) the total number of
2 full-time equivalent jobs created during the prior quarter,
3 (ii) the total number of employees as of the last day of the
4 prior quarter, (iii) the total number of full-time equivalent
5 hours in each job classification or job title, (iv) the total
6 number of incremental employees and contractors in support of
7 the investments undertaken pursuant to this subsection (b) for
8 the prior quarter, and (v) any other information that the
9 Commission may require by rule.

10 With respect to the participating utility's peak job
11 commitment, if, after considering the utility's corrective
12 action plan and compliance thereunder, the Commission enters an
13 order finding, after notice and hearing, that a participating
14 utility did not satisfy its peak job commitment described in
15 this subsection (b) for reasons that are reasonably within its
16 control, then the Commission shall also determine, after
17 consideration of the evidence, including, but not limited to,
18 evidence submitted by the Department of Commerce and Economic
19 Opportunity and the utility, the deficiency in the number of
20 full-time equivalent jobs during the peak program year due to
21 such failure. The Commission shall notify the Department of any
22 proceeding that is initiated pursuant to this paragraph. For
23 each full-time equivalent job deficiency during the peak
24 program year that the Commission finds as set forth in this
25 paragraph, the participating utility shall, within 30 days
26 after the entry of the Commission's order, pay \$6,000 to a fund

1 for training grants administered under Section 605-800 of the
2 Department of Commerce and Economic Opportunity Law, which
3 shall not be a recoverable expense.

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

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

26 In meeting the obligations of this subsection (b), to the

1 extent feasible and consistent with State and federal law, the
2 investments under the infrastructure investment program should
3 provide employment opportunities for all segments of the
4 population and workforce, including minority-owned and
5 female-owned business enterprises, and shall not, consistent
6 with State and federal law, discriminate based on race or
7 socioeconomic status.

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

18 If the participating utility finds that it is implementing
19 its plan for satisfying the infrastructure investment program
20 commitments described in subsection (b) of this Section at a
21 cost below the estimated amounts specified in subsection (b) of
22 this Section, then the utility may file a petition with the
23 Commission requesting that it be permitted to satisfy its
24 commitments by spending less than the estimated amounts
25 specified in subsection (b) of this Section. The Commission
26 shall, after notice and hearing, enter its order approving, or

1 approving as modified, or denying each such petition within 150
2 days after the filing of the petition.

3 In no event, absent General Assembly approval, shall the
4 capital investment costs incurred by a participating utility
5 other than a combination utility in satisfying its
6 infrastructure investment program commitments described in
7 subsection (b) of this Section exceed \$3,000,000,000 or, for a
8 participating utility that is a combination utility,
9 \$720,000,000. If the participating utility's updated cost
10 estimates for satisfying its infrastructure investment program
11 commitments described in subsection (b) of this Section exceed
12 the limitation imposed by this subsection (b-5), then it shall
13 submit a report to the Commission that identifies the increased
14 costs and explains the reason or reasons for the increased
15 costs no later than the year in which the utility estimates it
16 will exceed the limitation. The Commission shall review the
17 report and shall, within 90 days after the participating
18 utility files the report, report to the General Assembly its
19 findings regarding the participating utility's report. If the
20 General Assembly does not amend the limitation imposed by this
21 subsection (b-5), then the utility may modify its plan so as
22 not to exceed the limitation imposed by this subsection (b-5)
23 and may propose corresponding changes to the metrics
24 established pursuant to subparagraphs (5) through (8) of
25 subsection (f) of this Section, and the Commission may modify
26 the metrics and incremental savings goals established pursuant

1 to subsection (f) of this Section accordingly.

2 (b-10) All participating utilities shall make
3 contributions for an energy low-income and support program in
4 accordance with this subsection. Beginning no later than 180
5 days after a participating utility files a performance-based
6 formula rate tariff pursuant to subsection (c) of this Section,
7 or beginning no later than January 1, 2012 if such utility
8 files such performance-based formula rate tariff within 14 days
9 of December 30, 2011 (the effective date of Public Act 97-646),
10 and without obtaining any approvals from the Commission or any
11 other agency other than as set forth in this Section,
12 regardless of whether any such approval would otherwise be
13 required, a participating utility other than a combination
14 utility shall pay \$10,000,000 per year for 5 years and a
15 participating utility that is a combination utility shall pay
16 \$1,000,000 per year for 10 years to the energy low-income and
17 support program, which is intended to fund customer assistance
18 programs with the primary purpose being avoidance of imminent
19 disconnection. Such programs may include:

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

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

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

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

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

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

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

25 Programs that use funds that are provided by a
26 participating utility to reduce utility bills may be

1 implemented through tariffs that are filed with and reviewed by
2 the Commission. If a utility elects to file tariffs with the
3 Commission to implement all or a portion of the programs, those
4 tariffs shall, regardless of the date actually filed, be deemed
5 accepted and approved, and shall become effective on December
6 30, 2011 (the effective date of Public Act 97-646). The
7 participating utilities whose customers benefit from the funds
8 that are disbursed as contemplated in this Section shall file
9 annual reports documenting the disbursement of those funds with
10 the Commission. The Commission has the authority to audit
11 disbursement of the funds to ensure they were disbursed
12 consistently with this Section.

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

20 (b-15) Beginning in 2022, without obtaining any approvals
21 from the Commission or any other agency, regardless of whether
22 any such approval would otherwise be required, a participating
23 utility that is a combination utility shall pay \$1,000,000 per
24 year for 10 years to the energy low-income and support program,
25 which is intended to fund customer assistance programs with the
26 primary purpose of avoidance of imminent disconnection and

1 reconnecting customers who have been disconnected for
2 nonpayment. Such programs may include those described in
3 paragraphs (1) through (5) of subsection (b-10) of this
4 Section.

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

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

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

1 performance-based formula rate is otherwise terminated, then
2 the participating utility's voluntary commitments and
3 obligations under this subsection (b-15) shall immediately
4 terminate.

5 (c) A participating utility may elect to recover its
6 delivery services costs through a performance-based formula
7 rate approved by the Commission, which shall specify the cost
8 components that form the basis of the rate charged to customers
9 with sufficient specificity to operate in a standardized manner
10 and be updated annually with transparent information that
11 reflects the utility's actual costs to be recovered during the
12 applicable rate year, which is the period beginning with the
13 first billing day of January and extending through the last
14 billing day of the following December. In the event the utility
15 recovers a portion of its costs through automatic adjustment
16 clause tariffs on October 26, 2011 (the effective date of
17 Public Act 97-616), the utility may elect to continue to
18 recover these costs through such tariffs, but then these costs
19 shall not be recovered through the performance-based formula
20 rate. In the event the participating utility, prior to December
21 30, 2011 (the effective date of Public Act 97-646), filed
22 electric delivery services tariffs with the Commission
23 pursuant to Section 9-201 of this Act that are related to the
24 recovery of its electric delivery services costs that are still
25 pending on December 30, 2011 (the effective date of Public Act
26 97-646), the participating utility shall, at the time it files

1 its performance-based formula rate tariff with the Commission,
2 also file a notice of withdrawal with the Commission to
3 withdraw the electric delivery services tariffs previously
4 filed pursuant to Section 9-201 of this Act. Upon receipt of
5 such notice, the Commission shall dismiss with prejudice any
6 docket that had been initiated to investigate the electric
7 delivery services tariffs filed pursuant to Section 9-201 of
8 this Act, and such tariffs and the record related thereto shall
9 not be the subject of any further hearing, investigation, or
10 proceeding of any kind related to rates for electric delivery
11 services.

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

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

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

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

20 (3) Include a cost of equity, which in all rate years
21 for a participating utility that is not a combination
22 utility, and in each rate year commencing before December
23 1, 2019 for a participating utility that is a combination
24 utility, shall be calculated as the sum of the following:

25 (A) the average for the applicable calendar year of
26 the monthly average yields of 30-year U.S. Treasury

1 bonds published by the Board of Governors of the
2 Federal Reserve System in its weekly H.15 Statistical
3 Release or successor publication; and

4 (B) 580 basis points.

5 For a participating utility that is a combination
6 utility, for each rate year commencing after November 30,
7 2019, the cost of equity shall be calculated as the sum of
8 the following: (i) the average for the applicable calendar
9 year of the monthly average yields of 30-year U.S. Treasury
10 bonds published by the Board of Governors of the Federal
11 Reserve System in its weekly H.15 Statistical Release or
12 successor publication; and (ii) 680 basis points; however,
13 if the cost of equity as calculated under this paragraph
14 (3) for each rate year commencing after November 30, 2019,
15 for electric utilities that serve less than 3,000,000
16 retail customers but more than 500,000 retail customers in
17 this State is greater than the national average cost of
18 equity for the rate year by 50 basis points or more, then
19 the Illinois Commerce Commission shall include a cost of
20 equity at a rate equal to the national average cost of
21 equity as calculated under this paragraph (3) plus 50 basis
22 points. For purposes of this paragraph (3), the national
23 average cost of equity for a rate year shall be the simple
24 average of the cost of equity approved in each order of a
25 state regulatory commission, other than the Commission,
26 issued during that rate year that is applicable to retail

1 electric service provided by an investor-owned public
2 utility company operating in the United States. No order
3 shall be excluded from the national average cost of equity
4 calculated under this paragraph (3) on the grounds that it
5 is subject to rehearing or appeal. In the hearing during
6 the first rate year commencing after November 30, 2019, the
7 Commission shall set the cost of equity using the method
8 applicable to rate years commencing prior to December 1,
9 2019. In the hearings in rate years subsequent to such
10 first rate year, the Commission shall set the cost of
11 equity using the method applicable to rate years commencing
12 after November 30, 2019, including the reconciliation of
13 the first rate year commencing after November 30, 2019. If,
14 for any rate year, there are fewer than 15 applicable
15 orders of state regulatory commissions with which to
16 compute the average cost of equity, the Commission shall
17 include in the calculation of the national average the
18 number of state regulatory orders from the prior year or
19 years necessary to reach a total of 15, beginning with the
20 most recently issued and proceeding in reverse
21 chronological order.

22 At such time as the Board of Governors of the Federal
23 Reserve System ceases to include the monthly average yields
24 of 30-year U.S. Treasury bonds in its weekly H.15
25 Statistical Release or successor publication, the monthly
26 average yields of the U.S. Treasury bonds then having the

1 longest duration published by the Board of Governors in its
2 weekly H.15 Statistical Release or successor publication
3 shall instead be used for purposes of this paragraph (3).

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

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

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

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

26 (D) investment return at a rate equal to the

1 utility's weighted average cost of long-term debt, on
2 the pension assets as, and in the amount, reported in
3 Account 186 (or in such other Account or Accounts as
4 such asset may subsequently be recorded) of the
5 utility's most recently filed FERC Form 1, net of
6 deferred tax benefits;

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

18 (F) amortization over a 5-year period of the full
19 amount of each charge or credit that exceeds \$3,700,000
20 for a participating utility that is a combination
21 utility or \$10,000,000 for a participating utility
22 that serves more than 3 million retail customers in the
23 applicable calendar year and that relates to a
24 workforce reduction program's severance costs, changes
25 in accounting rules, changes in law, compliance with
26 any Commission-initiated audit, or a single storm or

1 other similar expense, provided that any unamortized
2 balance shall be reflected in rate base. For purposes
3 of this subparagraph (F), changes in law includes any
4 enactment, repeal, or amendment in a law, ordinance,
5 rule, regulation, interpretation, permit, license,
6 consent, or order, including those relating to taxes,
7 accounting, or to environmental matters, or in the
8 interpretation or application thereof by any
9 governmental authority occurring after October 26,
10 2011 (the effective date of Public Act 97-616);

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

13 (H) historical weather normalized billing
14 determinants; and

15 (I) allocation methods for common costs.

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

1 adjusting for any penalties to the rate of return on common
2 equity applied pursuant to the performance metrics
3 provision of subsection (f), (f-5), or (f-10) of this
4 Section, as applicable), then the participating utility
5 shall apply a credit through the performance-based formula
6 rate that reflects an amount equal to the value of that
7 portion of the earned rate of return on common equity that
8 is more than 50 basis points higher than the rate of return
9 on common equity calculated pursuant to paragraph (3) of
10 this subsection (c) (after adjusting for any penalties to
11 the rate of return on common equity applied pursuant to the
12 performance metrics provision of subsection (f), (f-5), or
13 (f-10) of this Section, as applicable) for the prior rate
14 year, adjusted for taxes. If the participating utility's
15 earned rate of return on common equity related to the
16 provision of delivery services for the prior rate year
17 (calculated using costs and capital structure approved by
18 the Commission as provided in subparagraph (2) of this
19 subsection (c), consistent with this Section, in
20 accordance with Commission rules and orders, including,
21 but not limited to, adjustments for goodwill, and after any
22 Commission-ordered disallowances and taxes) is more than
23 50 basis points less than the return on common equity
24 calculated pursuant to paragraph (3) of this subsection (c)
25 (after adjusting for any penalties to the rate of return on
26 common equity applied pursuant to the performance metrics

1 provision of subsection (f), (f-5), or (f-10) of this
2 Section, as applicable), then the participating utility
3 shall apply a charge through the performance-based formula
4 rate that reflects an amount equal to the value of that
5 portion of the earned rate of return on common equity that
6 is more than 50 basis points less than the rate of return
7 on common equity calculated pursuant to paragraph (3) of
8 this subsection (c) (after adjusting for any penalties to
9 the rate of return on common equity applied pursuant to the
10 performance metrics provision of subsection (f), (f-5), or
11 (f-10) of this Section, as applicable) for the prior rate
12 year, adjusted for taxes.

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

22 The utility shall file, together with its tariff, final
23 data based on its most recently filed FERC Form 1, plus
24 projected plant additions and correspondingly updated
25 depreciation reserve and expense for the calendar year in which
26 the tariff and data are filed, that shall populate the

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

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

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

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

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

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

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

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

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

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

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

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

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

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

14 Within 45 days after the utility files its annual update of
15 cost inputs to the performance-based formula rate, the
16 Commission shall have the authority, either upon complaint or
17 its own initiative, but with reasonable notice, to enter upon a
18 hearing concerning the prudence and reasonableness of the costs
19 incurred by the utility to be recovered during the applicable
20 rate year that are reflected in the inputs to the
21 performance-based formula rate derived from the utility's FERC
22 Form 1. During the course of the hearing, each objection shall
23 be stated with particularity and evidence provided in support
24 thereof, after which the utility shall have the opportunity to
25 rebut the evidence. Discovery shall be allowed consistent with
26 the Commission's Rules of Practice, which Rules shall be

1 enforced by the Commission or the assigned administrative law
2 judge. The Commission shall apply the same evidentiary
3 standards, including, but not limited to, those concerning the
4 prudence and reasonableness of the costs incurred by the
5 utility, in the hearing as it would apply in a hearing to
6 review a filing for a general increase in rates under Article
7 IX of this Act. The Commission shall not, however, have the
8 authority in a proceeding under this subsection (d) to consider
9 or order any changes to the structure or protocols of the
10 performance-based formula rate approved pursuant to subsection
11 (c) of this Section. In a proceeding under this subsection (d),
12 the Commission shall enter its order no later than the earlier
13 of 240 days after the utility's filing of its annual update of
14 cost inputs to the performance-based formula rate or December
15 31. The Commission's determinations of the prudence and
16 reasonableness of the costs incurred for the applicable
17 calendar year shall be final upon entry of the Commission's
18 order and shall not be subject to reopening, reexamination, or
19 collateral attack in any other Commission proceeding, case,
20 docket, order, rule or regulation, provided, however, that
21 nothing in this subsection (d) shall prohibit a party from
22 petitioning the Commission to rehear or appeal to the courts
23 the order pursuant to the provisions of this Act.

24 In the event the Commission does not, either upon complaint
25 or its own initiative, enter upon a hearing within 45 days
26 after the utility files the annual update of cost inputs to its

1 performance-based formula rate, then the costs incurred for the
2 applicable calendar year shall be deemed prudent and
3 reasonable, and the filed charges shall not be subject to
4 reopening, reexamination, or collateral attack in any other
5 proceeding, case, docket, order, rule, or regulation.

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

12 (e) Nothing in subsections (c) or (d) of this Section shall
13 prohibit the Commission from investigating, or a participating
14 utility from filing, revenue-neutral tariff changes related to
15 rate design of a performance-based formula rate that has been
16 placed into effect for the utility. Following approval of a
17 participating utility's performance-based formula rate tariff
18 pursuant to subsection (c) of this Section, the utility shall
19 make a filing with the Commission within one year after the
20 effective date of the performance-based formula rate tariff
21 that proposes changes to the tariff to incorporate the findings
22 of any final rate design orders of the Commission applicable to
23 the participating utility and entered subsequent to the
24 Commission's approval of the tariff. The Commission shall,
25 after notice and hearing, enter its order approving, or
26 approving with modification, the proposed changes to the

1 performance-based formula rate tariff within 240 days after the
2 utility's filing. Following such approval, the utility shall
3 make a filing with the Commission during each subsequent 3-year
4 period that either proposes revenue-neutral tariff changes or
5 re-files the existing tariffs without change, which shall
6 present the Commission with an opportunity to suspend the
7 tariffs and consider revenue-neutral tariff changes related to
8 rate design.

9 (f) Within 30 days after the filing of a tariff pursuant to
10 subsection (c) of this Section, each participating utility
11 shall develop and file with the Commission multi-year metrics
12 designed to achieve, ratably (i.e., in equal segments) over a
13 10-year period, improvement over baseline performance values
14 as follows:

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

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

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

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

3 (3.5) For a participating utility other than a
4 combination utility, 20% improvement in the System Average
5 Interruption Frequency Index for its Northeastern Region,
6 using a baseline of the average of the data from 2001
7 through 2010. For purposes of this paragraph (3.5),
8 Northeastern Region shall have the meaning set forth in the
9 participating utility's most recent report filed pursuant
10 to Section 16-125 of this Act.

11 (4) Seventy-five percent improvement in the total
12 number of customers who exceed the service reliability
13 targets as set forth in subparagraphs (A) through (C) of
14 paragraph (4) of subsection (b) of 83 Ill. Admin. Code Part
15 411.140 as of May 1, 2011, using 2010 as the baseline year.

16 (5) Reduction in issuance of estimated electric bills:
17 90% improvement for a participating utility other than a
18 combination utility, and 56% improvement for a
19 participating utility that is a combination utility, using
20 a baseline of the average number of estimated bills for the
21 years 2008 through 2010.

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

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

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

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

19 The definitions set forth in 83 Ill. Admin. Code Part
20 411.20 as of May 1, 2011 shall be used for purposes of
21 calculating performance under paragraphs (1) through (3.5) of
22 this subsection (f), provided, however, that the participating
23 utility may exclude up to 9 extreme weather event days from
24 such calculation for each year, and provided further that the
25 participating utility shall exclude 9 extreme weather event
26 days when calculating each year of the baseline period to the

1 extent that there are 9 such days in a given year of the
2 baseline period. For purposes of this Section, an extreme
3 weather event day is a 24-hour calendar day (beginning at 12:00
4 a.m. and ending at 11:59 p.m.) during which any weather event
5 (e.g., storm, tornado) caused interruptions for 10,000 or more
6 of the participating utility's customers for 3 hours or more.
7 If there are more than 9 extreme weather event days in a year,
8 then the utility may choose no more than 9 extreme weather
9 event days to exclude, provided that the same extreme weather
10 event days are excluded from each of the calculations performed
11 under paragraphs (1) through (3.5) of this subsection (f).

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

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

14 (f-5) The financial penalties applicable to the metrics
15 described in subparagraphs (1) through (8) of subsection (f) of
16 this Section, as applicable, shall be applied through an
17 adjustment to the participating utility's return on equity of
18 no more than a total of 30 basis points in each of the first 3
19 years, of no more than a total of 34 basis points in each of the
20 3 years thereafter, and of no more than a total of 38 basis
21 points in each of the 4 years thereafter, as follows:

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

25 (A) for each year that a participating utility
26 other than a combination utility does not achieve the

1 annual goal, the participating utility's return on
2 equity shall be reduced as follows: during years 1
3 through 3, by 5 basis points; during years 4 through 6,
4 by 6 basis points; and during years 7 through 10, by 7
5 basis points; and

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

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

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

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

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

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

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

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

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

20 The Commission shall, after notice and hearing, enter an
21 order within 120 days after the metrics are filed approving, or
22 approving with modification, a participating utility's tariff
23 or mechanism to satisfy the metrics set forth in subsection (f)
24 of this Section. On June 1 of each subsequent year, each
25 participating utility shall file a report with the Commission
26 that includes, among other things, a description of how the

1 participating utility performed under each metric and an
2 identification of any extraordinary events that adversely
3 impacted the utility's performance. Whenever a participating
4 utility does not satisfy the metrics required pursuant to
5 subsection (f) of this Section, the Commission shall, after
6 notice and hearing, enter an order approving financial
7 penalties in accordance with this subsection (f-5). The
8 Commission-approved financial penalties shall be applied
9 beginning with the next rate year. Nothing in this Section
10 shall authorize the Commission to reduce or otherwise obviate
11 the imposition of financial penalties for failing to achieve
12 one or more of the metrics established pursuant to subparagraph
13 (1) through (4) of subsection (f) of this Section.

14 (f-10) Each applicable 10-year period previously approved
15 by the Commission pursuant to subsections (f) and (f-5) of this
16 Section for a participating utility that is a combination
17 utility shall be extended for an additional 10-year period that
18 commences immediately after the termination of the previous
19 10-year period. The performance goals and financial penalties
20 applicable to each year of an additional 10-year period shall
21 be fixed at, and the same as, the performance goals applicable
22 to year 10 that were previously approved by the Commission
23 pursuant to subsections (f) and (f-5) of this Section and the
24 financial penalties applicable to year 10 set forth in
25 subsection (f-5) of this Section. The total amount of financial
26 penalties applicable in any given year shall not exceed 38

1 basis points. During the additional 10-year period, each
2 participating utility shall continue to file the annual reports
3 required by subsection (f-5) of this Section, and the
4 requirements of subsection (f-5) related to Commission
5 approval of any financial penalties shall continue to apply.
6 The tariff or tariffs approved under subsection (f-5) of this
7 Section for each participating utility that is a combination
8 utility shall remain in effect during the additional 10-year
9 period, and each participating utility that is a combination
10 utility is authorized to submit a compliance filing after the
11 effective date of this amendatory Act of the 101st General
12 Assembly conforming its tariff or tariffs to the provisions of
13 this subsection (f-10). In the event the formula rate tariff
14 established pursuant to subsection (c) of this Section
15 terminates, the utility's obligations under this subsection
16 (f-10) shall also terminate; however, the tariff mechanism
17 established pursuant to subsections (f) and (f-5) of this
18 Section, and extended under this subsection (f-10), shall
19 remain in effect until any penalties due and owing at the time
20 of such termination are applied.

21 The metrics and performance goals set forth in paragraphs
22 (5) through (8) of subsection (f) of this Section and extended
23 under this subsection (f-10), are based on the assumption that
24 the participating utility may fully implement the technology
25 described in subsection (b) of this Section, including
26 utilizing the full functionality of such technology and that

1 there is no requirement for personal on-site notification. If
2 the utility is unable to meet the metrics and performance goals
3 applicable to paragraphs (5) through (8) of subsection (f) of
4 this Section for such reasons during the additional 10-year
5 period, as those metrics and goals are set by this subsection
6 (f-10), and the Commission so finds after notice and hearing,
7 then the utility shall be excused from compliance, but only to
8 the limited extent achievement of the affected metrics and
9 performance goals was hindered by the less than full
10 implementation.

11 (g) On or before July 31, 2014, each participating utility
12 shall file a report with the Commission that sets forth the
13 average annual increase in the average amount paid per
14 kilowatthour for residential eligible retail customers,
15 exclusive of the effects of energy efficiency programs,
16 comparing the 12-month period ending May 31, 2012; the 12-month
17 period ending May 31, 2013; and the 12-month period ending May
18 31, 2014. For a participating utility that is a combination
19 utility with more than one rate zone, the weighted average
20 aggregate increase shall be provided. The report shall be filed
21 together with a statement from an independent auditor attesting
22 to the accuracy of the report. The cost of the independent
23 auditor shall be borne by the participating utility and shall
24 not be a recoverable expense. "The average amount paid per
25 kilowatthour" shall be based on the participating utility's
26 tariffed rates actually in effect and shall not be calculated

1 using any hypothetical rate or adjustments to actual charges
2 (other than as specified for energy efficiency) as an input.

3 In the event that the average annual increase exceeds 2.5%
4 as calculated pursuant to this subsection (g), then Sections
5 16-108.5, 16-108.6, 16-108.7, and 16-108.8 of this Act, other
6 than this subsection, shall be inoperative as they relate to
7 the utility and its service area as of the date of the report
8 due to be submitted pursuant to this subsection and the utility
9 shall no longer be eligible to annually update the
10 performance-based formula rate tariff pursuant to subsection
11 (d) of this Section. In such event, the then current rates
12 shall remain in effect until such time as new rates are set
13 pursuant to Article IX of this Act, subject to retroactive
14 adjustment, with interest, to reconcile rates charged with
15 actual costs, and the participating utility's voluntary
16 commitments and obligations under subsection (b) of this
17 Section shall immediately terminate, except for the utility's
18 obligation to pay an amount already owed to the fund for
19 training grants pursuant to a Commission order issued under
20 subsection (b) of this Section.

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

25 For purposes of this Section, the amount per kilowatthour
26 means the total amount paid for electric service expressed on a

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

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

12 (h) By December 31, 2017, the Commission shall prepare and
13 file with the General Assembly a report on the infrastructure
14 program and the performance-based formula rate. The report
15 shall include the change in the average amount per kilowatthour
16 paid by residential customers between June 1, 2011 and May 31,
17 2017. If the change in the total average rate paid exceeds 2.5%
18 compounded annually, the Commission shall include in the report
19 an analysis that shows the portion of the change due to the
20 delivery services component and the portion of the change due
21 to the supply component of the rate. The report shall include
22 separate sections for each participating utility.

23 This Section, other than this subsection (h), and Sections
24 16-108.5, 16-108.6, 16-108.7, and 16-108.8 of this Act, other
25 than this subsection (h), are inoperative after December 31,
26 2022 for every participating utility other than a combination

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

9 This Section, other than this subsection (h), and Sections
10 16-108.6, 16-108.7, and 16-108.8 of this Act are inoperative
11 after December 31, 2032 for every participating utility that is
12 a combination utility, after which time a participating utility
13 that is a combination utility shall no longer be eligible to
14 annually update the performance-based formula rate tariff
15 pursuant to subsection (d) of this Section. At such time, the
16 then current rates shall remain in effect until new rates are
17 set pursuant to Article IX of this Act, subject to retroactive
18 adjustment, with interest, to reconcile rates charged with
19 actual costs.

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

24 (i) While a participating utility may use, develop, and
25 maintain broadband systems and the delivery of broadband
26 services, voice-over-internet-protocol services,

1 telecommunications services, and cable and video programming
2 services for use in providing delivery services and Smart Grid
3 functionality or application to its retail customers,
4 including, but not limited to, the installation,
5 implementation and maintenance of Smart Grid electric system
6 upgrades as defined in Section 16-108.6 of this Act, a
7 participating utility is prohibited from offering to its retail
8 customers broadband services or the delivery of broadband
9 services, voice-over-internet-protocol services,
10 telecommunications services, or cable or video programming
11 services, unless they are part of a service directly related to
12 delivery services or Smart Grid functionality or applications
13 as defined in Section 16-108.6 of this Act, and from recovering
14 the costs of such offerings from retail customers.

15 (j) Nothing in this Section is intended to legislatively
16 overturn the opinion issued in Commonwealth Edison Co. v. Ill.
17 Commerce Comm'n, Nos. 2-08-0959, 2-08-1037, 2-08-1137,
18 1-08-3008, 1-08-3030, 1-08-3054, 1-08-3313 cons. (Ill. App.
19 Ct. 2d Dist. Sept. 30, 2010). Public Act 97-616 shall not be
20 construed as creating a contract between the General Assembly
21 and the participating utility, and shall not establish a
22 property right in the participating utility.

23 (k) The changes made in subsections (c) and (d) of this
24 Section by Public Act 98-15 are intended to be a restatement
25 and clarification of existing law, and intended to give binding
26 effect to the provisions of House Resolution 1157 adopted by

1 the House of Representatives of the 97th General Assembly and
2 Senate Resolution 821 adopted by the Senate of the 97th General
3 Assembly that are reflected in paragraph (3) of this
4 subsection. In addition, Public Act 98-15 preempts and
5 supersedes any final Commission orders entered in Docket Nos.
6 11-0721, 12-0001, 12-0293, and 12-0321 to the extent
7 inconsistent with the amendatory language added to subsections
8 (c) and (d).

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

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

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

13 (3) The tariff changes described in paragraphs (1) and
14 (2) of this subsection (k) shall relate only to, and be
15 consistent with, the following provisions of Public Act
16 98-15: paragraph (2) of subsection (c) regarding year-end
17 capital structure, subparagraph (D) of paragraph (4) of
18 subsection (c) regarding pension assets, and subsection
19 (d) regarding the reconciliation components related to
20 year-end rate base and interest calculated at a rate equal
21 to the utility's weighted average cost of capital.

22 (4) Nothing in this subsection is intended to effect a
23 dismissal of or otherwise affect an appeal from any final
24 Commission orders entered in Docket Nos. 11-0721, 12-0001,
25 12-0293, and 12-0321 other than to the extent of the
26 amendatory language contained in subsections (c) and (d) of

1 this Section of Public Act 98-15.

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

21 (A) if the Commission has initiated a proceeding
22 pursuant to subsection (e) of Section 16-108.6 of this Act
23 that is pending as of May 22, 2013 (the effective date of
24 Public Act 98-15), then the order entered in such
25 proceeding shall, after notice and hearing, accelerate the
26 commencement of the meter deployment schedule approved in

1 the final Commission order on rehearing entered in Docket
2 No. 12-0298;

3 (B) if the Commission has entered an order pursuant to
4 subsection (e) of Section 16-108.6 of this Act prior to May
5 22, 2013 (the effective date of Public Act 98-15) that does
6 not accelerate the commencement of the meter deployment
7 schedule approved in the final Commission order on
8 rehearing entered in Docket No. 12-0298, then the utility
9 shall file with the Commission, within 45 days after such
10 effective date, a plan for accelerating the commencement of
11 the utility's meter deployment schedule approved in the
12 final Commission order on rehearing entered in Docket No.
13 12-0298; the Commission shall reopen the proceeding in
14 which it entered its order pursuant to subsection (e) of
15 Section 16-108.6 of this Act and shall, after notice and
16 hearing, enter an amendatory order that approves or
17 approves as modified such accelerated plan within 90 days
18 after the utility's filing; or

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

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

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

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

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

18 (220 ILCS 5/16-108.19 new)

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

21 (a) Notwithstanding any other provisions of this Act and
22 without obtaining any approvals from the Commission or any
23 other agency, including, but not limited to, approvals
24 otherwise required under Section 8-406 of this Act, regardless
25 of whether any such approval would otherwise be required,

1 electric utilities that serve less than 3,000,000 retail
2 customers but more than 500,000 retail customers in this State
3 are authorized to, but are not required to, plan for,
4 construct, install, control, own, manage, or operate electric
5 vehicle charging infrastructure, including, but not limited
6 to, electric vehicle charging stations within their service
7 territories. Electric utilities that serve less than 3,000,000
8 retail customers but more than 500,000 retail customers in this
9 State may construct electric vehicle charging infrastructure
10 on private property or publicly owned property; however, the
11 Commission may not authorize an electric utility under Section
12 8-509 of this Act to acquire property rights by eminent domain
13 for the construction of any electric vehicle charging station.
14 Electric utilities that serve less than 3,000,000 retail
15 customers but more than 500,000 retail customers in this State
16 shall be allowed to recover all reasonable and prudent costs
17 associated with investment in the electric vehicle charging
18 infrastructure, including, but not limited to, costs to plan
19 for, construct, install, control, own, manage, or operate under
20 this Section through the applicable provisions of this Article
21 XVI or Article IX of this Act.

22 (b) Electric utilities that serve less than 3,000,000
23 retail customers but more than 500,000 retail customers in this
24 State may file with the Commission an electric vehicle charging
25 infrastructure deployment and charging facility rebate plan,
26 the purpose of which shall be to encourage the adoption of

1 electric vehicles in this State, including in the service
2 territory of the electric utilities subject to this Section.
3 The plan filed by an electric utility subject to this Section
4 shall identify a system of publicly accessible electric vehicle
5 charging stations and a schedule of rebates that would be
6 available to: (1) retail customers taking electric service from
7 the electric utility at an address in the electric utility's
8 service territory; and (2) any third party that would
9 construct, own, or operate a publicly accessible electric
10 vehicle charging station as authorized by this Section. The
11 Commission shall review the plan for compliance with the
12 provisions of this Section 16-108.19 and issue an order either
13 approving or modifying the plan within 180 days after the
14 initial filing. If the Commission finds that the plan filed
15 pursuant to this subsection (b) of this Section complies with
16 the requirements of subsections (c) and (d) of this Section,
17 the Commission shall approve the plan and the electric utility
18 shall implement it in accordance with the Commission approval.
19 If the Commission modifies the plan, the electric utility shall
20 notify the Commission in writing within 90 days after service
21 of the Commission's order modifying the plan as to whether the
22 electric utility accepts the Commission's modifications. If
23 the electric utility notifies the Commission in writing that it
24 does not accept the Commission's modifications, the electric
25 utility shall have no further obligations with respect to the
26 plan, including any obligation to implement the plan as

1 modified and may, at its discretion, file a new plan with the
2 Commission in the future. Upon approval by the Commission and
3 acceptance by the electric utility of a plan filed under this
4 subsection (b) of this Section, no further approvals by the
5 Commission other than those approvals set forth in this Section
6 shall be necessary and the electric utility shall implement the
7 approved plan in accordance with the Commission's approval.

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

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

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

26 (3) A proposed request for proposals process to be

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

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

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

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

26 (D) a proposal that provides the electric utility

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

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

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

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

22 (B) identification of available rebates for
23 multi-family residential buildings and non-residential
24 customers that, subsequent to the effective date of
25 this amendatory Act of the 101st General Assembly,
26 install and provide access to electric vehicle

1 charging facilities located in a common area generally
2 available to residents or the public;

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

10 (D) the manner and timing of the payment of the
11 proposed rebates; however, the rebates identified
12 pursuant to this paragraph (1) may be paid through a
13 monthly bill credit spread fairly and reasonably
14 across a 12-month period, and provided any customer
15 receiving a rebate must sign up for and remain on a
16 3-part delivery service rate, if available.

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

25 (e) An electric utility implementing a plan approved
26 pursuant to subsection (b) of this Section, may update its plan

1 at any time by filing such update with the Commission in the
2 same docket in which the Commission originally approved the
3 plan. Any updated filing made pursuant to this subsection (e)
4 must identify the updates to be implemented and any updates
5 shall be deemed approved as reasonable 45 days after the filing
6 unless the Commission initiates an investigation into the
7 updated actions. Any final order regarding the investigation
8 initiated pursuant to this subsection (e) must be issued within
9 180 days of the initiating order.

10 (f) Notwithstanding any other provision of law to the
11 contrary, electric utilities that serve less than 3,000,000
12 retail customers but more than 500,000 retail customers in this
13 State shall be permitted to recover all reasonable and
14 prudently incurred costs incurred under this Section,
15 including, but not limited to, any costs incurred to make any
16 location identified pursuant to subsections (b) and (c) of this
17 Section ready for installation and connection of an electric
18 vehicle charging station to the distribution system; the costs
19 incurred to provide the rebates identified pursuant to
20 subsections (b), (c), and (d) of this Section; the costs
21 incurred to undertake the education and engagement activities
22 authorized under this Section; and other costs incurred by the
23 utility to comply with and implement the requirements of this
24 Section, including any amounts that reasonably exceed any
25 estimates provided as part of the plan filed pursuant to
26 subsection (b) of this Section. Electric utilities that serve

1 less than 3,000,000 retail customers but more than 500,000
2 retail customers in this State are authorized to recover any
3 costs identified in this subsection (f) by way of a tariff or
4 tariffs approved by the Illinois Commerce Commission,
5 consistent with the following provisions:

6 (1) An electric utility subject to this Section shall
7 be permitted to recover all reasonable and prudently
8 incurred costs incurred to make any location identified
9 pursuant to subsections (b) and (c) of this Section ready
10 for installation and connection of an electric vehicle
11 charging station to the distribution system through its
12 delivery service rates, as authorized by the applicable
13 provisions of Article IX or this Article XVI. For any
14 electric vehicle infrastructure identified in any plan
15 filed pursuant to subsections (b) and (c) of this Section,
16 distribution extension free allowances up to and including
17 \$1,500 per kilowatt of electric vehicle charging station
18 expected peak demand shall be deemed reasonable and shall
19 not limit the use of alternate extension provisions
20 demonstrated to be more favorable and approved by the
21 Illinois Commerce Commission.

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

1 paragraph (1) of this subsection (f) of this Section, as a
2 regulatory asset, to be amortized over a 15-year period.
3 The unamortized balance shall be recognized as of December
4 31 for a given year. The utility shall also earn a return
5 on the total of the unamortized balance of the regulatory
6 asset authorized under this Section, less any deferred
7 taxes related to the unamortized balance, at an annual rate
8 equal to the utility's weighted average cost of capital
9 that includes, based on a year-end capital structure, the
10 utility's actual cost of debt for the applicable calendar
11 year and a cost of equity, which shall be calculated as the
12 sum of the following: (i) the average for the applicable
13 calendar year of the monthly average yields of 30-year U.S.
14 Treasury bonds published by the Board of Governors of the
15 Federal Reserve System in its weekly H.15 Statistical
16 Release or successor publication; and (ii) 680 basis
17 points; however, if the cost of equity as calculated under
18 this paragraph (2) is greater than the national average
19 cost of equity for the rate year by 50 basis points or
20 more, then the Illinois Commerce Commission shall include a
21 cost of equity at a rate equal to the national average cost
22 of equity as calculated under this paragraph (2) plus 50
23 basis points. For purposes of this paragraph (2), the
24 national average cost of equity for a rate year shall be
25 the simple average of the cost of equity approved in each
26 order of a state regulatory commission, other than the

1 Commission, issued during that rate year that is applicable
2 to retail electric service provided by an investor-owned
3 public utility company operating in the United States. No
4 order shall be excluded from the national average cost of
5 equity calculated under this paragraph (2) on the grounds
6 that it is subject to rehearing or appeal. If, for any rate
7 year, there are fewer than 15 applicable orders of state
8 regulatory commissions with which to compute the average
9 cost of equity, the Commission shall include in the
10 calculation of the national average the number of state
11 regulatory orders from the prior year or years necessary to
12 reach a total of 15, beginning with the most recently
13 issued and proceeding in reverse chronological order. At
14 such time as the Board of Governors of the Federal Reserve
15 System ceases to include the monthly average yields of
16 30-year U.S. Treasury bonds in its weekly H.15 Statistical
17 Release or successor publication, the monthly average
18 yields of the U.S. Treasury bonds then having the longest
19 duration published by the Board of Governors in its weekly
20 H.15 Statistical Release or successor publication shall
21 instead be used for purposes of this paragraph (2).

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

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

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

1 adjustment clause tariff; provided that nothing in this
2 paragraph (4) of this subsection (f) permits the double
3 recovery of such costs from customers. Such costs shall be
4 allocated across all classes of retail customers in
5 proportion to delivery service revenue requirement
6 attributed to a class. If the electric utility elects to
7 recover the costs it incurs under this Section through an
8 automatic adjustment clause tariff, the utility may file
9 its proposed tariff together with the plan it files under
10 subsection (b) of this Section or at a later time. The
11 proposed tariff shall provide for an annual
12 reconciliation, less any deferred taxes related to the
13 reconciliation, with interest at an annual rate of return
14 equal to the utility's weighted average cost of capital as
15 calculated under paragraph (2) of this subsection (f),
16 including a revenue conversion factor calculated to
17 recover or refund all additional income taxes that may be
18 payable or receivable as a result of that return, of the
19 revenue requirement reflected in rates for each calendar
20 year, beginning with the calendar year in which the utility
21 files its automatic adjustment clause tariff under this
22 subsection (f), with what the revenue requirement would
23 have been had the actual cost information for the
24 applicable calendar year been available at the filing date.
25 The tariff may permit recovery of costs through a single
26 cents per kilowatt-hour charge applicable to each retail

1 class. The Commission shall review the proposed tariff and
2 may make changes to the tariff that are consistent with
3 this Section and with the Commission's authority under
4 Article IX of this Act, subject to notice and hearing, as
5 required. Following notice and hearing, as required, the
6 Commission shall issue an order approving, or approving
7 with modification, such tariff no later than 240 days after
8 the electric utility files its tariff.

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

23 (h) In addition to the plan authorized in subsection (b),
24 electric utilities that serve less than 3,000,000 retail
25 customers but more than 500,000 retail customers in this State
26 shall be permitted to administer programs designed to encourage

1 or incentivize the adoption of electric vehicles by Illinois
2 electric consumers, and such programs shall not be prohibited
3 by the Commission as promotional practices under any rules or
4 policies of the Commission, including, but not limited to, 83
5 Ill. Adm. Code Part 275.

6 (220 ILCS 5/16-108.20 new)

7 Sec. 16-108.20. Electric energy storage.

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

14 (b) Notwithstanding any other provision of law to the
15 contrary, an electric utility subject to this Section shall be
16 permitted to recover all reasonable and prudently incurred
17 costs incurred under this Section, including, but not limited
18 to, the costs incurred to plan for, construct, control, own,
19 manage, or operate the infrastructure and undertake activities
20 identified in this Section in a reasonable and prudent manner
21 pursuant to Article IX or this Article XVI, as applicable, and
22 for purposes of cost recovery the energy storage facilities
23 shall be treated as distribution assets; provided that: (1) the
24 Commission shall have the authority to determine the
25 reasonableness of the costs of the facilities; and (2) any

1 monetary value of power and energy from the facilities shall be
2 credited against the delivery services revenue requirement. An
3 electric utility subject to this Section shall operate storage
4 for the primary purpose of facilitating stable and reliable
5 delivery service, and any loss incidental to the operation of
6 storage facilities shall also be recoverable to the extent such
7 losses were prudently incurred as a result of the operation of
8 the facility.

9 (220 ILCS 5/16-128A)

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

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

18 For purposes of this Section, the phrase "entities
19 installing distributed generation facilities" shall include,
20 but not be limited to, all entities that are exempt from the
21 definition of "alternative retail electric supplier" under
22 item (v) of Section 16-102 of this Act. For purposes of this
23 Section, the phrase "self-installer" means an individual who
24 (i) leases or purchases a cogeneration facility for his or her
25 own personal use and (ii) installs such cogeneration or

1 self-generation facility on his or her own premises without the
2 assistance of any other person.

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

16 (c) No electric utility shall provide a retail customer
17 with net metering service related to interconnection of that
18 customer's distributed generation facility unless the customer
19 provides the electric utility with (i) a certification that the
20 customer installing the distributed generation facility was a
21 self-installer or (ii) evidence that the distributed
22 generation facility was installed by an entity certified under
23 this Section that is also in good standing with the Commission.
24 For purposes of this subsection, a retail customer includes
25 that customer's employees, officers, and agents. An electric
26 utility shall file a tariff or tariffs with the Commission

1 setting forth the documentation, as specified by Commission
2 rule, that a retail customer must provide to an electric
3 utility. The provisions of this subsection (c) shall apply on
4 or after the effective date of the Commission's rules
5 prescribed pursuant to subsection (a) of this Section.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6 (13) identify and determine the training or other
7 programs by which persons or entities may obtain the
8 requisite training, skills, or experience necessary to
9 achieve and maintain compliance with the requirements set
10 forth in this subsection and subsection (a) of Section
11 16-128 to install, maintain, or repair electric vehicle
12 charging stations.

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

18 All retail customers who own, maintain, or repair an
19 electric vehicle charging station shall provide the servicing
20 electric utility (i) a certification that the customer
21 installing the electric vehicle charging station was a
22 self-installer or (ii) evidence that the electric vehicle
23 charging station was installed by an entity certified under
24 this subsection (d) that is also in good standing with the
25 Commission. For purposes of this subsection (d), a retail
26 customer includes that retail customer's employees, officers,

1 and agents. If the electric vehicle charging station was not
2 installed by a self-installer, then the person or entity that
3 plans to install the electric vehicle charging station shall
4 provide notice to the servicing electric utility prior to
5 installation and when installation is complete and provide any
6 other information required by the Commission's rules
7 established under subsection (d) of this Section. An electric
8 utility shall file a tariff or tariffs with the Commission
9 setting forth the documentation, as specified by Commission
10 rule, that a retail customer who owns, uses, operates, or
11 maintains an electric vehicle charging station must provide to
12 an electric utility.

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

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

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

1 rules.

2 (g) Within 18 months of the effective date of this
3 amendatory Act of the 99th General Assembly, the Commission
4 shall adopt rules, including emergency rules, establishing a
5 process for entities installing a new utility-scale solar
6 project to certify compliance with the requirements of this
7 Section. For purposes of this Section, the phrase "entities
8 installing a new utility-scale solar project" shall include,
9 but is not limited to, any entity installing new photovoltaic
10 projects as such terms are defined in subsection (c) of Section
11 1-75 of the Illinois Power Agency Act.

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

20 (h) In addition to any authority granted to the Commission
21 under this Act, the Commission is also authorized to: (1)
22 determine which entities are subject to certification under
23 subsection (g) of this Section; (2) impose reasonable
24 certification fees and penalties; (3) adopt disciplinary
25 procedures; (4) investigate any and all activities subject to
26 subsection (g) or this subsection (h) of this Section,

1 including violations thereof; (5) adopt procedures to issue or
2 renew, or to refuse to issue or renew, a certification or to
3 revoke, suspend, place on probation, reprimand, or otherwise
4 discipline a certified entity under subsection (g) of this
5 Section or take other enforcement action against an entity
6 subject to subsection (g) or this subsection (h) of this
7 Section; (6) prescribe forms to be issued for the
8 administration and enforcement of subsection (g) and this
9 subsection (h) of this Section; and (7) establish requirements
10 to ensure that entities installing a new photovoltaic project
11 have the requisite knowledge, skills, training, experience,
12 and competence to perform in a safe and reliable manner as
13 required by subsection (a) of Section 16-128 of this Act.

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

1 distributed generation facilities, or electric vehicle
2 charging stations. This Section is a limitation under
3 subsection (h) of Section 6 of Article VII of the Illinois
4 Constitution on the exercise by home rule units of powers and
5 functions exclusively exercised by the State.

6 (Source: P.A. 99-906, eff. 6-1-17; 100-16, eff. 6-30-17.)

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

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

1 INDEX

2 Statutes amended in order of appearance

3 20 ILCS 3855/1-10

4 20 ILCS 3855/1-75

5 220 ILCS 5/8-103B

6 220 ILCS 5/8-218 new

7 220 ILCS 5/16-102

8 220 ILCS 5/16-107.6

9 220 ILCS 5/16-108.5

10 220 ILCS 5/16-108.19 new

11 220 ILCS 5/16-108.20 new

12 220 ILCS 5/16-128A