



## 104TH GENERAL ASSEMBLY

### State of Illinois

2025 and 2026

SB3929

Introduced 2/6/2026, by Sen. Patrick J. Joyce

#### SYNOPSIS AS INTRODUCED:

20 ILCS 3855/1-5  
220 ILCS 5/16-108.18  
415 ILCS 5/9.15

Amends the Illinois Power Agency Act. Provides that it is the policy of the State to rapidly transition to 100% clean energy by 2060 (rather than 2050). Amends the Public Utilities Act. In provisions relating to performance incentives and metrics for electric utilities designed to encourage those utilities to support and facilitate the State's clean energy transition, extends timelines by 10 years from existing statutory dates to allow for competitive market development and cost declines. Amends the Environmental Protection Act. Provides that all electricity generating units and large greenhouse gas-emitting units that use coal or oil as a fuel and are not public GHG-emitting units shall permanently reduce all CO<sub>2</sub>e and co-pollutant emissions to zero no later than January 1, 2040 (rather than 2030). Further provides that All EGUs and large greenhouse gas-emitting units that use coal as a fuel and are public GHG-emitting units shall permanently reduce CO<sub>2</sub>e emissions to zero no later than December 31, 2055 (rather than 2045). Provides that if the emissions reduction requirement is not achieved by December 31, 2045 (rather than 2035), the plant shall retire one or more units or otherwise reduce its CO<sub>2</sub>e emissions by 45% from existing emissions by June 30, 2048 (rather than 2038). Provides that no later than January 1, 2050 (rather than 2040) all EGUs and large greenhouse gas-emitting units that have a NO<sub>x</sub> emission rate of greater than 0.12 lbs/MWh or a SO<sub>2</sub> emission rate greater than 0.006 lb/MWh, and are not located in or within 3 miles of an environmental justice community designated as of January 1, 2021 or an equity investment eligible community shall permanently reduce all CO<sub>2</sub>e and co-pollutant emissions to zero, including through unit retirement or the use of 100% green hydrogen or other similar technology that is commercially proven to achieve zero carbon emissions.

LRB104 19036 BDA 32481 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 5. The Illinois Power Agency Act is amended by  
5 changing Section 1-5 as follows:

6 (20 ILCS 3855/1-5)

7 Sec. 1-5. Legislative declarations and findings. The  
8 General Assembly finds and declares:

9 (1) The health, welfare, and prosperity of all  
10 Illinois residents require the provision of adequate,  
11 reliable, affordable, efficient, and environmentally  
12 sustainable electric service at the lowest total cost over  
13 time, taking into account any benefits of price stability.

14 (1.5) To provide the highest quality of life for the  
15 residents of Illinois and to provide for a clean and  
16 healthy environment, it is the policy of this State to  
17 rapidly transition to 100% clean energy by 2060 ~~2050~~.

18 (2) (Blank).

19 (3) (Blank).

20 (4) It is necessary to improve the process of  
21 procuring electricity to serve Illinois residents, to  
22 promote investment in energy efficiency and  
23 demand-response measures, and to maintain and support

1 development of clean coal technologies, generation  
2 resources that operate at all hours of the day and under  
3 all weather conditions, zero emission facilities, and  
4 renewable resources.

5 (5) Procuring a diverse electricity supply portfolio  
6 will ensure the lowest total cost over time for adequate,  
7 reliable, efficient, and environmentally sustainable  
8 electric service.

9 (6) Including renewable resources and zero emission  
10 credits from zero emission facilities in that portfolio  
11 will reduce long-term direct and indirect costs to  
12 consumers by decreasing environmental impacts and by  
13 avoiding or delaying the need for new generation,  
14 transmission, and distribution infrastructure. Developing  
15 new renewable energy resources in Illinois, including  
16 brownfield solar projects and community solar projects,  
17 will help to diversify Illinois electricity supply, avoid  
18 and reduce pollution, reduce peak demand, and enhance  
19 public health and well-being of Illinois residents.

20 (7) Developing community solar projects in Illinois  
21 will help to expand access to renewable energy resources  
22 to more Illinois residents.

23 (8) Developing brownfield solar projects in Illinois  
24 will help return blighted or contaminated land to  
25 productive use while enhancing public health and the  
26 well-being of Illinois residents, including those in

1 environmental justice communities.

2 (9) Energy efficiency, demand-response measures, zero  
3 emission energy, and renewable energy are resources  
4 currently underused in Illinois. These resources should be  
5 used, when cost effective, to reduce costs to consumers,  
6 improve reliability, and improve environmental quality and  
7 public health.

8 (10) The State should encourage the use of advanced  
9 clean coal technologies that capture and sequester carbon  
10 dioxide emissions to advance environmental protection  
11 goals and to demonstrate the viability of coal and  
12 coal-derived fuels in a carbon-constrained economy.

13 (10.5) The State should encourage the development of  
14 interregional high voltage direct current (HVDC)  
15 transmission lines that benefit Illinois. All ratepayers  
16 in the State served by the regional transmission  
17 organization where the HVDC converter station is  
18 interconnected benefit from the long-term price stability  
19 and market access provided by interregional HVDC  
20 transmission facilities. The benefits to Illinois include:  
21 reduction in wholesale power prices; access to lower-cost  
22 markets; enabling the integration of additional renewable  
23 generating units within the State through near  
24 instantaneous dispatchability and the provision of  
25 ancillary services; creating good-paying union jobs in  
26 Illinois; and, enhancing grid reliability and climate

1 resilience via HVDC facilities that are installed  
2 underground.

3 (10.6) The health, welfare, and safety of the people  
4 of the State are advanced by developing new HVDC  
5 transmission lines predominantly along transportation  
6 rights-of-way, with an HVDC converter station that is  
7 located in the service territory of a public utility as  
8 defined in Section 3-105 of the Public Utilities Act  
9 serving more than 3,000,000 retail customers, and with a  
10 project labor agreement as defined in Section 1-10 of this  
11 Act.

12 (11) The General Assembly enacted Public Act 96-0795  
13 to reform the State's purchasing processes, recognizing  
14 that government procurement is susceptible to abuse if  
15 structural and procedural safeguards are not in place to  
16 ensure independence, insulation, oversight, and  
17 transparency.

18 (12) The principles that underlie the procurement  
19 reform legislation apply also in the context of power  
20 purchasing.

21 (13) To ensure that the benefits of installing  
22 renewable resources are available to all Illinois  
23 residents and located across the State, subject to  
24 appropriation, it is necessary for the Agency to provide  
25 public information and educational resources on how  
26 residents can benefit from the expansion of renewable

1 energy in Illinois and participate in the Illinois Solar  
2 for All Program established in Section 1-56, the  
3 Adjustable Block program established in Section 1-75, the  
4 job training programs established by paragraph (1) of  
5 subsection (a) of Section 16-108.12 of the Public  
6 Utilities Act, and the programs and resources established  
7 by the Energy Transition Act.

8 The General Assembly therefore finds that it is necessary  
9 to create the Illinois Power Agency and that the goals and  
10 objectives of that Agency are to accomplish each of the  
11 following:

12 (A) Develop electricity procurement plans to ensure  
13 adequate, reliable, affordable, efficient, and  
14 environmentally sustainable electric service at the lowest  
15 total cost over time, taking into account any benefits of  
16 price stability, for electric utilities that on December  
17 31, 2005 provided electric service to at least 100,000  
18 customers in Illinois and for small multi-jurisdictional  
19 electric utilities that (i) on December 31, 2005 served  
20 less than 100,000 customers in Illinois and (ii) request a  
21 procurement plan for their Illinois jurisdictional load.  
22 The procurement plan shall be updated on an annual basis  
23 and shall include renewable energy resources and,  
24 beginning with the delivery year commencing June 1, 2017,  
25 zero emission credits from zero emission facilities  
26 sufficient to achieve the standards specified in this Act.

1           (B) Conduct the competitive procurement processes  
2 identified in this Act.

3           (C) Develop electric generation and co-generation  
4 facilities that use indigenous coal or renewable  
5 resources, or both, financed with bonds issued by the  
6 Illinois Finance Authority.

7           (D) Supply electricity from the Agency's facilities at  
8 cost to one or more of the following: municipal electric  
9 systems, governmental aggregators, or rural electric  
10 cooperatives in Illinois.

11           (E) Ensure that the process of power procurement is  
12 conducted in an ethical and transparent fashion, immune  
13 from improper influence.

14           (F) Continue to review its policies and practices to  
15 determine how best to meet its mission of providing the  
16 lowest cost power to the greatest number of people, at any  
17 given point in time, in accordance with applicable law.

18           (G) Operate in a structurally insulated, independent,  
19 and transparent fashion so that nothing impedes the  
20 Agency's mission to secure power at the best prices the  
21 market will bear, provided that the Agency meets all  
22 applicable legal requirements.

23           (H) Implement renewable energy procurement and  
24 training programs throughout the State to diversify  
25 Illinois electricity supply, improve reliability, avoid  
26 and reduce pollution, reduce peak demand, and enhance

1 public health and well-being of Illinois residents,  
2 including low-income residents.

3 (Source: P.A. 102-662, eff. 9-15-21.)

4 Section 10. The Public Utilities Act is amended by  
5 changing Section 16-108.18 as follows:

6 (220 ILCS 5/16-108.18)

7 Sec. 16-108.18. Performance-based ratemaking.

8 (a) The General Assembly finds:

9 (1) That improving the alignment of utility customer  
10 and company interests is critical to ensuring equity,  
11 rapid growth of distributed energy resources, electric  
12 vehicles, and other new technologies that substantially  
13 change the makeup of the grid and protect Illinois  
14 residents and businesses from potential economic and  
15 environmental harm from the State's energy systems.

16 (2) There is urgency around addressing increasing  
17 threats from climate change and assisting communities that  
18 have borne disproportionate impacts from climate change,  
19 including air pollution, greenhouse gas emissions, and  
20 energy burdens. Addressing this problem requires changes  
21 to the business model under which utilities in Illinois  
22 have traditionally functioned.

23 (3) Providing targeted incentives to support change  
24 through a new performance-based structure to enhance

1           ratemaking is intended to enable alignment of utility,  
2           customer, community, and environmental goals.

3           (4) Though Illinois has taken some measures to move  
4           utilities to performance-based ratemaking through the  
5           establishment of performance incentives and a  
6           performance-based formula rate under the Energy  
7           Infrastructure Modernization Act, these measures have not  
8           been sufficiently transformative in urgently moving  
9           electric utilities toward the State's ambitious energy  
10          policy goals: protecting a healthy environment and  
11          climate, improving public health, and creating quality  
12          jobs and economic opportunities, including wealth  
13          building, especially in economically disadvantaged  
14          communities and communities of color.

15          (5) These measures were not developed through a  
16          process to understand first what performance measures and  
17          penalties would help drive the sought-after behavior by  
18          the utilities.

19          (6) While the General Assembly has not made a finding  
20          that the spending related to the Energy Infrastructure and  
21          Modernization Act and its performance metrics was not  
22          reasonable, it is important to address concerns that these  
23          measures may have resulted in excess utility spending and  
24          guaranteed profits without meaningful improvements in  
25          customer experience, rate affordability, or equity.

26          (7) Discussions of performance incentive mechanisms

1 must always take into account the affordability of  
2 customer rates and bills for all customers, including  
3 low-income customers.

4 (8) The General Assembly therefore directs the  
5 Illinois Commerce Commission to complete a transition that  
6 includes a comprehensive performance-based regulation  
7 framework for electric utilities serving more than 500,000  
8 customers. The breadth of this framework should revise  
9 existing utility regulations to position Illinois electric  
10 utilities to effectively and efficiently achieve current  
11 and anticipated future energy needs of this State, while  
12 ensuring affordability for consumers.

13 (b) As used in this Section:

14 "Commission" means the Illinois Commerce Commission.

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

18 "Distributed energy resources" or "DER" means a wide range  
19 of technologies that are connected to the grid including those  
20 that are located on the customer side of the customer's  
21 electric meter and can provide value to the distribution  
22 system, including, but not limited to, distributed generation,  
23 energy storage, electric vehicles, and demand response  
24 technologies.

25 "Economically disadvantaged communities" means areas of  
26 one or more census tracts where average household income does

1 not exceed 80% of area median income.

2 "Environmental justice communities" means the definition  
3 of that term as used and as may be updated in the long-term  
4 renewable resources procurement plan by the Illinois Power  
5 Agency and its Program Administrator in the Illinois Solar for  
6 All Program.

7 "Equity investment eligible community" means the  
8 geographic areas throughout Illinois which would most benefit  
9 from equitable investments by the State designed to combat  
10 discrimination. Specifically, the equity investment eligible  
11 communities shall be defined as the following areas:

12 (1) R3 Areas as established pursuant to Section 10-40  
13 of the Cannabis Regulation and Tax Act, where residents  
14 have historically been excluded from economic  
15 opportunities, including opportunities in the energy  
16 sector; and

17 (2) Environmental justice communities, as defined by  
18 the Illinois Power Agency pursuant to the Illinois Power  
19 Agency Act, where residents have historically been subject  
20 to disproportionate burdens of pollution, including  
21 pollution from the energy sector.

22 "Performance incentive mechanism" means an instrument by  
23 which utility performance is incentivized, which could include  
24 a monetary performance incentive.

25 "Performance metric" means a manner of measurement for a  
26 particular utility activity.

1 (c) Through coordinated, comprehensive system planning,  
2 ratemaking, and performance incentives, the performance-based  
3 ratemaking framework should be designed to accomplish the  
4 following objectives:

5 (1) maintain and improve service reliability and  
6 safety, including and particularly in environmental  
7 justice, low-income, and equity investment eligible  
8 communities;

9 (2) decarbonize utility systems at a pace that meets  
10 or exceeds State climate goals, while also ensuring the  
11 affordability of rates for all customers, including  
12 low-income customers;

13 (3) direct electric utilities to make cost-effective  
14 investments that support achievement of Illinois' clean  
15 energy policies, including, at a minimum, investments  
16 designed to integrate distributed energy resources, comply  
17 with critical infrastructure protection standards, plans,  
18 and industry best practices, and support and take  
19 advantage of potential benefits from the electric vehicle  
20 charging and other electrification, while mitigating the  
21 impacts;

22 (4) choose cost-effective assets and services, whether  
23 utility-supplied or through third-party contracting,  
24 considering both economic and environmental costs and the  
25 effects on utility rates, to deliver high-quality service  
26 to customers at least cost;

1           (5) maintain the affordability of electric delivery  
2 services for all customers, including low-income  
3 customers;

4           (6) maintain and grow a diverse workforce, diverse  
5 supplier procurement base and, for relevant programs,  
6 diverse approved-vendor pools, including increased  
7 opportunities for minority-owned, female-owned,  
8 veteran-owned, and disability-owned business enterprises;

9           (7) improve customer service performance and  
10 engagement;

11           (8) address the particular burdens faced by consumers  
12 in environmental justice and equity investment eligible  
13 communities, including shareholder, consumer, and publicly  
14 funded bill payment assistance and credit and collection  
15 policies, and ensure equitable disconnections, late fees,  
16 or arrearages as a result of utility credit and collection  
17 practices, which may include consideration of impact by  
18 zip code; and

19           (9) implement or otherwise enhance current supplier  
20 diversity programs to increase diverse contractor  
21 participation in professional services, subcontracting,  
22 and prime contracting opportunities with programs that  
23 address barriers to access. Supplier diversity programs  
24 shall address specific barriers related to RFP and  
25 contract access, access to capital, information technology  
26 and cybersecurity ~~cyber~~ security access and costs,

1 administrative burdens, and quality control with specific  
2 metrics, outcomes, and demographic data reported.

3 (d) Multi-Year Rate Plan.

4 (1) If an electric utility had a performance-based  
5 formula rate in effect under Section 16-108.5 as of  
6 December 31, 2020, then the utility may file a petition  
7 proposing tariffs implementing a 4-year Multi-Year Rate  
8 Plan as provided in this Section no later than, January  
9 20, 2023, for delivery service rates to be effective for  
10 the billing periods January 1, 2024 through December 31,  
11 2027. The Commission shall issue an order approving or  
12 approving as modified the utility's plan no later than  
13 December 20, 2023. The term "Multi-Year Rate Plan" refers  
14 to a plan establishing the base rates the utility shall  
15 charge for each delivery year of the 4-year period to be  
16 covered by the plan, which shall be subject to  
17 modification only as expressly allowed in this Section.

18 (2) A utility proposing a Multi-Year Rate Plan shall  
19 provide a 4-year investment plan and a description of the  
20 utility's major planned investments, including, at a  
21 minimum, all investments of \$2,000,000 or greater over the  
22 plan period for an electric utility that serves more than  
23 3,000,000 retail customers in the State or \$500,000 for an  
24 electric utility that serves less than 3,000,000 retail  
25 customers in the State but more than 500,000 retail  
26 customers in the State. The 4-year investment plan must be

1 consistent with the Multi-Year Integrated Grid Plan  
2 described in Section 16-105.17 of this Act. The investment  
3 plan shall provide sufficiently detailed information, as  
4 required by the Commission, including, at a minimum, a  
5 description of each investment, the location of the  
6 investment, and an explanation of the need for and benefit  
7 of such an investment to the extent known.

8 (3) The Multi-Year Rate Plan shall be implemented  
9 through a tariff filed with the Commission consistent with  
10 the provisions of this paragraph (3) that shall apply to  
11 all delivery service customers. The Commission shall  
12 initiate and conduct an investigation of the tariff in a  
13 manner consistent with the provisions of this paragraph  
14 (3) and the provisions of Article IX of this Act, to the  
15 extent they do not conflict with this paragraph (3). The  
16 Multi-Year Rate Plan approved by the Commission shall do  
17 the following:

18 (A) Provide for the recovery of the utility's  
19 forecasted rate base, based on the 4-year investment  
20 plan and the utility's Integrated Grid Plan. The  
21 forecasted rate base must include the utility's  
22 planned capital investments, with rates based on  
23 average annual plant investment, and  
24 investment-related costs, including income tax  
25 impacts, depreciation, and ratemaking adjustments and  
26 costs that are prudently incurred and reasonable in

1 amount consistent with Commission practice and law.  
2 The process used to develop the forecasts must be  
3 iterative, rigorous, and lead to forecasts that  
4 reasonably represent the utility's investments during  
5 the forecasted period and ensure that the investments  
6 are projected to be used and useful during the annual  
7 investment period and least cost, consistent with the  
8 provisions of Articles VIII and IX of this Act.

9 (B) The cost of equity shall be approved by the  
10 Commission consistent with Commission practice and  
11 law.

12 (C) The revenue requirement shall reflect the  
13 utility's actual capital structure for the applicable  
14 calendar year. A year-end capital structure that  
15 includes a common equity ratio of up to and including  
16 50% of the total capital structure shall be deemed  
17 prudent and reasonable. A higher common equity ratio  
18 must be specifically approved by the Commission.

19 (D) (Blank).

20 (E) Provide for recovery of prudent and reasonable  
21 projected operating expenses, giving effect to  
22 ratemaking adjustments, consistent with Commission  
23 practice and law under Article IX of this Act.  
24 Operating expenses for years after the first year of  
25 the Multi-Year Rate Plan may be estimated by the use of  
26 known and measurable changes, expense reductions

1 associated with planned capital investments as  
2 appropriate, and reasonable and appropriate  
3 escalators, indices, or other metrics.

4 (F) Amortize the amount of unprotected  
5 property-related excess accumulated deferred income  
6 taxes in rates as of January 1, 2023 over a period  
7 ending December 31, 2027, unless otherwise required to  
8 amortize the excess deferred income tax pursuant to  
9 Section 16-108.21 of this Act.

10 (G) Allow recovery of incentive compensation  
11 expense that is based on the achievement of  
12 operational metrics, including metrics related to  
13 budget controls, outage duration and frequency,  
14 safety, customer service, efficiency and productivity,  
15 environmental compliance and attainment of  
16 affordability and environmental goals, and other goals  
17 and metrics approved by the Commission. Incentive  
18 compensation expense that is based on net income or an  
19 affiliate's earnings per share shall not be  
20 recoverable.

21 (H) To the maximum extent practicable, align the  
22 4-year investment plan and annual capital budgets with  
23 the electric utility's Multi-Year Integrated Grid  
24 Plan.

25 (4) The Commission shall establish annual rates for  
26 each year of the Multi-Year Rate Plan that accurately

1 reflect and are based only upon the utility's reasonable  
2 and prudent costs of service over the term of the plan,  
3 including the effect of all ratemaking adjustments  
4 consistent with Commission practice and law as determined  
5 by the Commission, provided that the costs are not being  
6 recovered elsewhere in rates. Tariff riders authorized by  
7 the Commission may continue outside of a plan authorized  
8 under this Section to the extent such costs are not  
9 recovered elsewhere in rates. For the first Multi-Year  
10 Rate Plan, the burden of proof shall be on the electric  
11 utility to establish the prudence of investments and  
12 expenditures and to establish that such investments  
13 consistent with and reasonably necessary to meet the  
14 requirements of the utility's first approved Multi-Year  
15 Integrated Grid Plan described in Section 16-105.17 of  
16 this Act. For subsequent Multi-Year Rate Plans, the burden  
17 of proof shall be on the electric utility to establish the  
18 prudence of investments and expenditures and to establish  
19 that such investments are consistent with and reasonably  
20 necessary to meet the requirements of the utility's most  
21 recently approved Multi-Year Integrated Grid Plan  
22 described in Section 16-105.17 of this Act. The sole fact  
23 that a cost differs from that incurred in a prior period or  
24 that an investment is different from that described in the  
25 Multi-Year Integrated Grid Plan shall not imply the  
26 imprudence or unreasonableness of that cost or investment.

1 The sole fact that an investment is the same or similar to  
2 that described in the Multi-Year Integrated Grid Plan  
3 shall not imply prudence and reasonableness of that  
4 investment.

5 (5) To facilitate public transparency, all materials,  
6 data, testimony, and schedules shall be provided to the  
7 Commission in an editable, machine-readable electronic  
8 format including .doc, .docx, .xls, .xlsx, and similar  
9 file formats, but not including .pdf or .exif. Should  
10 utilities designate any materials confidential, they shall  
11 have an affirmative duty to explain why the particular  
12 information is marked confidential. In determining  
13 prudence and reasonableness of rates, the Commission shall  
14 make its determination based upon the record, including  
15 each public comment filed or provided orally at open  
16 meetings consistent with the Commission's rules and  
17 practices.

18 (6) The Commission may, by order, establish terms,  
19 conditions, and procedures for submitting and approving a  
20 Multi-Year Rate Plan necessary to implement this Section  
21 and ensure that rates remain just and reasonable during  
22 the course of the plan, including terms and procedures for  
23 rate adjustment.

24 (7) An electric utility that files a tariff pursuant  
25 to paragraph (3) of this subsection (d) ~~(e)~~ must submit a  
26 one-time \$300,000 filing fee at the time the Chief Clerk

1 of the Commission accepts the filing, which shall be a  
2 recoverable expense.

3 (8) An electric utility operating under a Multi-Year  
4 Rate Plan shall file a new Multi-Year Rate Plan at least  
5 300 days prior to the end of the initial Multi-Year Rate  
6 Plan unless it elects to file a general rate case pursuant  
7 to paragraph (9), and every 4 years thereafter, with a  
8 rate-effective date of the proposed tariffs such that,  
9 after the Commission suspension period, the rates would  
10 take effect immediately at the close of the final year of  
11 the initial Multi-Year Rate Plan. In subsequent Multi-Year  
12 Rate Plans, as in the initial plans, utilities and  
13 stakeholders may propose additional metrics that achieve  
14 the outcomes described in paragraph (2) of subsection (f)  
15 of this Section.

16 (9) Election of Rate Case.

17 (A) On or before the date prescribed by  
18 subparagraph (B) of this paragraph (9) ~~of this~~  
19 ~~Section~~, electric utilities that serve more than  
20 500,000 retail customers in the State shall file  
21 either a general rate case under Section 9-201 of this  
22 Act, or a Multi-Year Rate Plan, as set forth in  
23 paragraph (1) of this subsection (d).

24 (B) Electric utilities described in subparagraph  
25 (A) of this paragraph (9) ~~of this Section~~ shall file  
26 their initial general rate case or Multi-Year Rate

1 Plan, as applicable, with the Commission no later than  
2 January 20, 2023.

3 (C) Notwithstanding which rate filing option an  
4 electric utility elects to file on the date prescribed  
5 by subparagraph (B) of this paragraph (9) ~~of this~~  
6 ~~Section~~, the electric utility shall be subject to the  
7 Multi-year Integrated Plan filing requirements.

8 (D) Following its initial rate filing pursuant to  
9 paragraph (2), an electric utility subject to the  
10 requirements of this Section shall thereafter be  
11 permitted to elect a different rate filing option  
12 consistent with any filing intervals established for a  
13 general rate case or Multi-Year Rate Plan, as follows:

14 (i) An electric utility that initially elected  
15 to file a Multi-Year Rate Plan and thereafter  
16 elects to transition to a general rate case may do  
17 so upon completion of the 4-year Multi-Year Rate  
18 Plan by filing a general rate case at the same time  
19 that the utility would have filed its subsequent  
20 Multi-Year Rate Plan, as specified in paragraph  
21 (8) of this subsection (d). Notwithstanding this  
22 election, the annual adjustment of the final year  
23 of the Multi-Year Rate Plan shall proceed as  
24 specified in paragraph (6) of subsection (f).

25 (ii) An electric utility that initially  
26 elected to a file general rate case and thereafter

1 elects to transition to a Multi-Year Rate Plan may  
2 do so only at the 4-year filing intervals  
3 identified by paragraph (8) of this subsection  
4 (d).

5 (10) The Commission shall approve tariffs establishing  
6 rate design for all delivery service customers unless the  
7 electric utility makes the election specified in Section  
8 16-105.5, in which case the rate design shall be subject  
9 to the provisions of that Section.

10 (11) The Commission shall establish requirements for  
11 annual performance evaluation reports to be submitted  
12 annually for performance metrics. Such reports shall  
13 include, but not be limited to, a description of the  
14 utility's performance under each metric and an  
15 identification of any extraordinary events that adversely  
16 affected the utility's performance.

17 (12) For the first Multi-Year Rate Plan, the  
18 Commission shall consolidate its investigation with the  
19 proceeding under Section 16-105.17 to establish the  
20 Multi-Year Integrated Grid Plan no later than 45 days  
21 after plan filing.

22 (13) Where a rate change under a Multi-Year Rate Plan  
23 will result in a rate increase, an electric utility may  
24 propose a rate phase-in plan that the Commission shall  
25 approve with or without modification or deny in its final  
26 order approving the new delivery services rates. A

1 proposed rate phase-in plan under this paragraph (13) must  
2 allow the new delivery services rates to be implemented in  
3 no more than 2 steps, as follows: in the first step, at  
4 least 50% of the approved rate increase must be reflected  
5 in rates, and, in the second step, 100% of the rate  
6 increase must be reflected in rates. The second step's  
7 rates must take effect no later than 12 months after the  
8 first step's rates were placed into effect. The portion of  
9 the approved rate increase not implemented in the first  
10 step shall be recorded on the electric utility's books as  
11 a regulatory asset, and shall accrue carrying costs to  
12 ensure that the utility does not recover more or less than  
13 it otherwise would because of the deferral. This portion  
14 shall be recovered, with such carrying costs at the  
15 weighted average cost of capital, through a surcharge  
16 applied to retail customer bills that (i) begins no later  
17 than 12 months after the date on which the second step's  
18 rates went into effect and (ii) is applied over a period  
19 not to exceed 24 months. Nothing in this paragraph is  
20 intended to limit the Commission's authority to mitigate  
21 the impact of rates caused by rate plans, or any other  
22 instance on a revenue-neutral basis; nor shall it mitigate  
23 a utility's ability to make proposals to mitigate the  
24 impact of rates. When a deferral, or similar method, is  
25 used to mitigate the impact of rates, the utility should  
26 be allowed to recover carrying costs.

1           (14) Notwithstanding the provisions of paragraph (13),  
2           the Commission may, on its own initiative, take  
3           revenue-neutral measures to relieve the impact of rate  
4           increases on customers. Such initiatives may be taken by  
5           the Commission in the first Multi-Year Rate Plan,  
6           subsequent multi-year plans, or in other instances  
7           described in this Act.

8           (15) Whenever during the pendency of a Multi-Year Rate  
9           Plan, an electric utility subject to this Section becomes  
10          aware that, due to circumstances beyond its control,  
11          prudent operating practices will require the utility to  
12          make adjustments to the Multi-Year Rate Plan, the electric  
13          utility may file a petition with the Commission requesting  
14          modification of the approved annual revenue requirements  
15          included in the Multi-Year Rate Plan. The electric utility  
16          must support its request with evidence demonstrating why a  
17          modification is necessary, due to circumstances beyond the  
18          utility's control, to follow prudent operating practices  
19          and must set forth the changes to each annual revenue  
20          requirement to be approved, and the basis for any changes  
21          in anticipated operating expenses or capital investment  
22          levels. The utility shall affirmatively address the impact  
23          of the changes on the Multi-Year Integrated Grid Plan and  
24          Multi-Year Rate Plan originally submitted and approved by  
25          the Commission. Any interested party may file an objection  
26          to the changes proposed, or offer alternatives to the

1 utility's proposal, as supported by testimony and  
2 evidence. After notice and hearing, the Commission shall  
3 issue a final order regarding the electric utility's  
4 request no later than 180 days after the filing of the  
5 petition.

6 (e) Performance incentive mechanisms.

7 (1) The electric industry is undergoing rapid  
8 transformation, including fundamental changes in how  
9 electricity is generated, procured, and delivered and how  
10 customers are choosing to participate in the supply and  
11 delivery of electricity to and from the electric grid.  
12 Building upon the State's goals to increase the  
13 procurement of electricity from renewable energy  
14 resources, including distributed generation and storage  
15 devices, the General Assembly finds that electric  
16 utilities should make cost-effective investments that  
17 support moving forward on Illinois' clean energy policies.  
18 It is therefore in the State's interest for the Commission  
19 to establish performance incentive mechanisms in order to  
20 better tie utility revenues to performance and customer  
21 benefits, accelerate progress on Illinois energy and other  
22 goals, ensure equity and affordability of rates for all  
23 customers, including low-income customers, and hold  
24 utilities publicly accountable.

25 (2) The Commission shall approve, based on the  
26 substantial evidence proffered in the proceeding initiated

1       pursuant to this subsection performance metrics that, to  
2       the extent practicable and achievable by the electric  
3       utility, encourage cost-effective, equitable utility  
4       achievement of the outcomes described in this subsection  
5       (e) while ensuring no degradation in the significant  
6       performance improvement achieved through previously  
7       established performance metrics. For each electric  
8       utility, the Commission shall approve metrics designed to  
9       achieve incremental improvements over baseline performance  
10      values and targets, over a performance period of up to 10  
11      years, and no less than 4 years, with timelines extended  
12      by 10 years from existing statutory dates to allow for  
13      competitive market development and cost declines.

14               (A) The Commission shall approve no more than 8  
15      metrics, with at least one metric from each of the  
16      categories below, for each electric utility, from  
17      items (i) through (vi) of this subparagraph (A). Upon  
18      a utility request, the Commission may approve the use  
19      of a specific, measurable, and achievable tracking  
20      metric described in paragraph (3) of this subsection  
21      (e) as a performance metric pursuant to paragraph (2)  
22      of this subsection (e).

23               (i) Metrics designed to ensure the utility  
24      maintains and improves the high standards of both  
25      overall and locational reliability and resiliency,  
26      and makes improvements in power quality, including

1 and particularly in environmental justice and  
2 equity investment eligible communities.

3 (ii) Peak load reductions attributable to  
4 demand response programs.

5 (iii) Supplier diversity expansion, including  
6 diverse contractor participation in professional  
7 services, subcontracting, and prime contracting  
8 opportunities, development of programs that  
9 address the barriers to access, aligning  
10 demographics of contractors to the demographics in  
11 the utility's service territory, establish  
12 long-term mentoring relationships that develop and  
13 remove barriers to access for diverse and  
14 underserved contractors. The utilities shall  
15 provide solutions, resources, and tools to address  
16 complex barriers of entry related to costly and  
17 time-intensive cybersecurity ~~cyber~~ security  
18 requirements, increasingly complex information  
19 technology requirements, insurance barriers,  
20 service provider sign-up process barriers,  
21 administrative process barriers, and other  
22 barriers that inhibit access to RFPs and  
23 contracts. For programs with contracts over  
24 \$1,000,000, winning bidders must demonstrate a  
25 subcontractor development or mentoring  
26 relationship with at least one of their diverse

1 subcontracting partners for a core component of  
2 the scope of the project. The mentoring time and  
3 cost shall be taken into account in the creation  
4 of RFP and shall include a structured and measured  
5 plan by the prime contractor to increase the  
6 capabilities of the subcontractor in their  
7 proposed scope. The metric shall include reporting  
8 on all supplier diversity programs by goals,  
9 program results, demographics and geography, with  
10 separate reporting by category of minority-owned,  
11 female-owned, veteran-owned, and disability-owned  
12 business enterprise metrics. The report shall  
13 include resources and expenses committed to the  
14 programs and conversion rates of new diverse  
15 utility contractors.

16 (iv) Achieve affordable customer delivery  
17 service costs, with particular emphasis on keeping  
18 the bills of lower-income households, households  
19 in equity investment eligible communities, and  
20 household in environmental justice communities  
21 within a manageable portion of their income and  
22 adopting credit and collection policies that  
23 reduce disconnections for these households  
24 specifically and for customers overall to ensure  
25 equitable disconnections, late fees, or arrearages  
26 as a result of utility credit and collection

1 practices, which may include consideration of  
2 impact by zip code.

3 (v) Metrics designed around the utility's  
4 timeliness to customer requests for  
5 interconnection in key milestone areas, such as:  
6 initial response, supplemental review, and system  
7 feasibility study; improved average service  
8 reliability index for those customers that have  
9 interconnected a distributed renewable energy  
10 generation device to the utility's distribution  
11 system and are lawfully taking service under an  
12 applicable tariff; offering a variety of  
13 affordable rate options, including demand  
14 response, time of use rates for delivery and  
15 supply, real-time pricing rates for supply;  
16 comprehensive and predictable net metering, and  
17 maximizing the benefits of grid modernization and  
18 clean energy for ratepayers; and improving  
19 customer access to utility system information  
20 according to consumer demand and interest.

21 (vi) Metrics designed to measure the utility's  
22 customer service performance, which may include  
23 the average length of time to answer a customer's  
24 call by a customer service representative, the  
25 abandoned call rate and the relative ranking of  
26 the electric utility, by a reputable third-party

1 organization, in customer service satisfaction  
2 when compared to other similar electric utilities  
3 in the Midwest region.

4 (B) Performance metrics shall include a  
5 description of the metric, a calculation method, a  
6 data collection method, annual performance targets,  
7 and any incentives or penalties for the utility's  
8 achievement of, or failure to achieve, their  
9 performance targets, provided that the total amount of  
10 potential incentives and penalties shall be  
11 symmetrical. Incentives shall be rewards or penalties  
12 or both, reflected as basis points added to, or  
13 subtracted from, the utility's cost of equity. The  
14 metrics and incentives shall apply for the entire time  
15 period covered by a Multi-Year Rate Plan. The total  
16 for all metrics shall be equal to 40 basis points,  
17 however, the Commission may adjust the basis points  
18 upward or downward by up to 20 basis points for any  
19 given Multi-Year Rate Plan, as appropriate, but in no  
20 event may the total exceed 60 basis points or fall  
21 below 20 basis points.

22 (C) Metrics related to reliability shall be  
23 implemented to ensure equitable benefits to  
24 environmental justice and equity investment eligible  
25 communities, as defined in this Act.

26 (D) The Commission shall approve performance

1 metrics that are reasonably within control of the  
2 utility to achieve. The Commission also shall not  
3 approve a metric that is solely expected to have the  
4 effect of reducing the workforce. Performance metrics  
5 should measure outcomes and actual, rather than  
6 projected, results where possible. Nothing in this  
7 subparagraph is intended to require that different  
8 electric utilities must be subject to the same  
9 metrics, goals, or incentives.

10 (E) Increases or enhancements to an existing  
11 performance goal or target shall be considered in  
12 light of other metrics, cost-effectiveness, and other  
13 factors the Commission deems appropriate. Performance  
14 metrics shall include one year of tracking data  
15 collected in a consistent manner, verifiable by an  
16 independent evaluator in order to establish a baseline  
17 and measure outcomes and actual results against  
18 projections where possible.

19 (F) For the purpose of determining reasonable  
20 performance metrics and related incentives, the  
21 Commission shall develop a methodology to calculate  
22 net benefits that includes customer and societal costs  
23 and benefits and quantifies the effect on delivery  
24 rates. In determining the appropriate level of a  
25 performance incentive, the Commission shall consider:  
26 the extent to which the amount is likely to encourage

1 the utility to achieve the performance target in the  
2 least cost manner; the value of benefits to customers,  
3 the grid, public health and safety, and the  
4 environment from achievement of the performance  
5 target, including in particular benefits to equity  
6 investment eligible community; the affordability of  
7 customer's electric bills, including low-income  
8 customers, the utility's revenue requirement, the  
9 promotion of renewable and distributed energy, and  
10 other such factors that the Commission deems  
11 appropriate. The consideration of these factors shall  
12 result in an incentive level that ensures benefits  
13 exceed costs for customers.

14 (G) Achievement of performance metrics are based  
15 on the assumptions that the utility will adopt or  
16 implement the technology and equipment, and make the  
17 investments to the extent reasonably necessary to  
18 achieve the goal. If the electric utility is unable to  
19 meet the performance metrics as a result of  
20 extraordinary circumstances outside of its control,  
21 including, but not limited to, government-declared  
22 emergencies, then the utility shall be permitted to  
23 file a petition with the Commission requesting that  
24 the utility be excused from compliance with the  
25 applicable performance goal or goals and the  
26 associated financial incentives and penalties. The

1           burden of proof shall be on the utility, consistent  
2           with Article IX, and the utility's petition shall be  
3           supported by substantial evidence. The Commission  
4           shall, after notice and hearing, enter its order  
5           approving or denying, in whole or in part, the  
6           utility's petition based on the extent to which the  
7           utility demonstrated that its achievement of the  
8           affected metrics and performance goals was hindered by  
9           extraordinary circumstances outside of the utility's  
10          control.

11          (3) The Commission shall approve reasonable and  
12          appropriate tracking metrics to collect and monitor data  
13          for the purpose of measuring and reporting utility  
14          performance and for establishing future performance  
15          metrics. These additional tracking metrics shall include  
16          at least one metric from each of the following categories  
17          of performance:

18                 (A) Minimize emissions of greenhouse gases and  
19                 other air pollutants that harm human health,  
20                 particularly in environmental justice and equity  
21                 investment eligible communities, through minimizing  
22                 total emissions by accelerating electrification of  
23                 transportation, buildings, and industries where such  
24                 electrification results in net reductions, across all  
25                 fuels and over the life of electrification measures,  
26                 of greenhouse gases and other pollutants, taking into

1 consideration the fuel mix used to produce electricity  
2 at the relevant hour and the effect of accelerating  
3 electrification on electricity delivery services  
4 rates, supply prices, and peak demand, provided the  
5 revenues the utility receives from accelerating  
6 electrification of transportation, buildings, and  
7 industries exceed the costs, with timelines extended  
8 by 10 years from existing statutory dates to allow for  
9 competitive market development and cost declines.

10 (B) Enhance the grid's flexibility to adapt to  
11 increased deployment of nondispatchable resources,  
12 improve the ability and performance of the grid on  
13 load balancing, and offer a variety of rate plans to  
14 match consumer consumption patterns and lower consumer  
15 bills for electricity delivery and supply.

16 (C) Ensure rates reflect cost savings attributable  
17 to grid modernization and utilize distributed energy  
18 resources that allow the utility to defer or forgo  
19 traditional grid investments that would otherwise be  
20 required to provide safe and reliable service.

21 (D) Metrics designed to create and sustain  
22 full-time-equivalent jobs and opportunities for all  
23 segments of the population and workforce, including  
24 minority-owned businesses, women-owned businesses,  
25 veteran-owned businesses, and businesses owned by a  
26 person or persons with a disability, and that do not,

1 consistent with State and federal law, discriminate  
2 based on race or socioeconomic status as a result of  
3 Public Act 102-662.

4 (E) Maximize and prioritize the allocation of grid  
5 planning benefits to environmental justice and  
6 economically disadvantaged customers and communities,  
7 such that all metrics provide equitable benefits  
8 across the utility's service territory and maintain  
9 and improve utility customers' access to uninterrupted  
10 utility services.

11 (4) The Commission may establish new tracking and  
12 performance metrics in future Multi-Year Rate Plans to  
13 further measure achievement of the outcomes set forth in  
14 paragraph (2) of subsection (f) of this Section and the  
15 other goals and requirements of this Section.

16 (5) The Commission shall also evaluate metrics that  
17 were established in prior Multi-Year Rate Plans to  
18 determine if there has been an unanticipated material  
19 change in circumstances such that adjustments are required  
20 to improve the likelihood of the outcomes described in  
21 paragraph (2) of subsection (f). For metrics that were  
22 established in prior Multi-Year Rate Plan proceedings and  
23 that the Commission elects to continue, the design of  
24 these metrics, including the goals of tracking metrics and  
25 the targets and incentive levels and structures of  
26 performance metrics, may be adjusted pursuant to the

1 requirements in this Section. The Commission may also  
2 change, adjust, or phase out tracking and performance  
3 metrics that were established in prior Multi-Year Rate  
4 Plan proceedings if these metrics no longer meet the  
5 requirements of this Section or if they are rendered  
6 obsolete by the changing needs and technology of an  
7 evolving grid. Additionally, performance metrics that no  
8 longer require an incentive to create improved utility  
9 performance may become tracking metrics in a Multi-Year  
10 Rate Plan proceeding.

11 (6) The Commission shall initiate a workshop process  
12 no later than August 1, 2021, or 15 days after September  
13 15, 2021 (the effective date of Public Act 102-662),  
14 whichever is later, for the purpose of facilitating the  
15 development of metrics for each utility. The workshop  
16 shall be coordinated by the staff of the Commission, or a  
17 facilitator retained by staff, and shall be organized and  
18 facilitated in a manner that encourages representation  
19 from diverse stakeholders and ensures equitable  
20 opportunities for participation, without requiring formal  
21 intervention or representation by an attorney. Working  
22 with staff of the Commission the facilitator may conduct a  
23 combination of workshops specific to a utility or  
24 applicable to multiple utilities where content and  
25 stakeholders are substantially similar. The workshop  
26 process shall conclude no later than October 31, 2021.

1           Following the workshop, the staff of the Commission, or  
2           the facilitator retained by the Staff, shall prepare and  
3           submit a report to the Commission that identifies the  
4           participants in the process, the metrics proposed during  
5           the process, any material issues that remained unresolved  
6           at the conclusions of such process, and any  
7           recommendations for workshop process improvements. Any  
8           workshop participant may file comments and reply comments  
9           in response to the Staff report.

10                   (A) No later than January, 20, 2022, each electric  
11           utility that intends to file a petition pursuant to  
12           subsection (b) of this Section shall file a petition  
13           with the Commission seeking approval of its  
14           performance metrics, which shall include for each  
15           metric, at a minimum, (i) a detailed description, (ii)  
16           the calculation of the baseline, (iii) the performance  
17           period and overall performance goal, provided that the  
18           performance period shall not commence prior to January  
19           1, 2024, (iv) each annual performance goal, (v) the  
20           performance adjustment, which shall be a symmetrical  
21           basis point increase or decrease to the utility's cost  
22           of equity based on the extent to which the utility  
23           achieved the annual performance goal, and (vi) the new  
24           or modified tariff mechanism that will apply the  
25           performance adjustments. The Commission shall issue  
26           its order approving, or approving with modification,

1 the utility's proposed performance metrics no later  
2 than September 30, 2022.

3 (B) No later than August 1, 2025, the Commission  
4 shall initiate a workshop process that conforms to the  
5 workshop purpose and requirements of this paragraph  
6 (6) of this Section to the extent they do not conflict.  
7 The workshop process shall conclude no later than  
8 October 31, 2025, and the staff of the Commission, or  
9 the facilitator retained by the Staff, shall prepare  
10 and submit a report consistent with the requirements  
11 described in this paragraph (6) of this Section. No  
12 later than January 20, 2026, each electric utility  
13 subject to the requirements of this Section shall file  
14 a petition that reflects, and is consistent with, the  
15 components required in this paragraph (6) of this  
16 Section, and the Commission shall issue its order  
17 approving, or approving with modification, the  
18 utility's proposed performance metrics no later than  
19 September 30, 2026.

20 (f) On May 1 of each year, following the approval of the  
21 first Multi-Year Rate Plan and its initial year, the  
22 Commission shall open an annual performance evaluation  
23 proceeding to evaluate the utilities' performance on their  
24 metric targets during the year just completed, as well as the  
25 appropriate Annual Adjustment as defined in paragraph (6). The  
26 Commission shall determine the performance and annual

1 adjustments to be applied through a surcharge in the following  
2 calendar year.

3 (1) On February 15 of each year, prior to the annual  
4 performance evaluation proceeding, each utility shall file  
5 a performance evaluation report with the Commission that  
6 includes a description of and all data supporting how the  
7 utility performed under each performance metric and an  
8 identification of any extraordinary events that adversely  
9 impacted the utility's performance.

10 (2) The metrics approved under this Section are based  
11 on the assumptions that the utility may fully implement  
12 the technology and equipment, and make the investments,  
13 required to achieve the metrics and performance goals. If  
14 the utility is unable to meet the metrics and performance  
15 goals because it was hindered by unanticipated technology  
16 or equipment implementation delays, government-declared  
17 emergencies, or other investment impediments, then the  
18 utility shall be permitted to file a petition with the  
19 Commission on or before the date that its report is due  
20 pursuant to paragraph (1) of this subsection (f)  
21 requesting that the utility be excused from compliance  
22 with the applicable performance goal or goals. The burden  
23 of proof shall be on the utility, consistent with Article  
24 IX, and the utility's petition shall be supported by  
25 substantial evidence. No later than 90 days after the  
26 utility files its petition, the Commission shall, after

1 notice and hearing, enter its order approving or denying,  
2 in whole or in part, the utility's petition based on the  
3 extent to which the utility demonstrated that its  
4 achievement of the affected metrics and performance goals  
5 was hindered by unanticipated technology or equipment  
6 implementation delays, or other investment impediments,  
7 that were reasonably outside of the utility's control.

8 (3) The electric utility shall provide for an annual  
9 independent evaluation of its performance on metrics. The  
10 independent evaluator shall review the utility's  
11 assumptions, baselines, targets, calculation  
12 methodologies, and other relevant information, especially  
13 ensuring that the utility's data for establishing  
14 baselines matches actual performance, and shall provide a  
15 report to the Commission in each annual performance  
16 evaluation describing the results. The independent  
17 evaluator shall present this report as evidence as a  
18 nonparty participant and shall not be represented by the  
19 utility's legal counsel. The independent evaluator shall  
20 be hired through a competitive bidding process with  
21 approval of the contract by the Commission.

22 The Commission shall consider the report of the  
23 independent evaluator in determining the utility's  
24 achievement of performance targets. Discrepancies between  
25 the utility's assumptions, baselines, targets, or  
26 calculations and those of the independent evaluator shall

1           be closely scrutinized by the Commission. If the  
2           Commission finds that the utility's reported data for any  
3           metric or metrics significantly and incorrectly deviates  
4           from the data reported by the independent evaluator, then  
5           the Commission shall order the utility to revise its data  
6           collection and calculation process within 60 days, with  
7           specifications where appropriate.

8           (4) The Commission shall, after notice and hearing in  
9           the annual performance evaluation proceeding, enter an  
10          order approving the utility's performance adjustment based  
11          on its achievement of or failure to achieve its  
12          performance targets no later than December 20 each year.  
13          The Commission-approved penalties or incentives shall be  
14          applied beginning with the next calendar year.

15          (5) In order to promote the transparency of utility  
16          investments during the effective period of a multi-year  
17          rate plan, inform the Commission's investigation and  
18          adjustment of rates in the annual adjustment process, and  
19          to facilitate the participation of stakeholders in the  
20          annual adjustment process, an electric utility with an  
21          effective Multi-Year Rate Plan shall, within 90 days of  
22          the close of each quarter during the Multi-Year Rate Plan  
23          period, submit to the Commission a report that summarizes  
24          the additions to utility plant that were placed into  
25          service during the prior quarter, which for purposes of  
26          the report shall be the most recently closed fiscal

1 quarter. The report shall also summarize the utility plant  
2 the electric utility projects it will place into service  
3 through the end of the calendar year in which the report is  
4 filed. The projections, estimates, plans, and  
5 forward-looking information that are provided in the  
6 reports pursuant to this paragraph (5) are for planning  
7 purposes and are intended to be illustrative of the  
8 investments that the utility proposes to make as of the  
9 time of submittal. Nothing in this paragraph (5)  
10 precludes, or is intended to limit, a utility's ability to  
11 modify and update its projections, estimates, plans, and  
12 forward-looking information previously submitted in order  
13 to reflect stakeholder input or other new or updated  
14 information and analysis, including, but not limited to,  
15 changes in specific investment needs, customer electric  
16 use patterns, customer applications and preferences, and  
17 commercially available equipment and technologies, however  
18 the utility shall explain any changes or deviations  
19 between the projected investments from the quarterly  
20 reports and actual investments in the annual report. The  
21 reports submitted pursuant to this subsection are intended  
22 to be flexible planning tools, and are expected to evolve  
23 as new information becomes available. Within 7 days of  
24 receiving a quarterly report, the Commission shall timely  
25 make such report available to the public by posting it on  
26 the Commission's website. Each quarterly report shall

1 include the following detail:

2 (A) The total dollar value of the additions to  
3 utility plant placed in service during the prior  
4 quarter;

5 (B) A list of the major investment categories the  
6 electric utility used to manage its routine standing  
7 operational activities during the prior quarter  
8 including the total dollar amount for the work  
9 reflected in each investment category in which utility  
10 plant in service is equal to or greater than  
11 \$2,000,000 for an electric utility that serves more  
12 than 3,000,000 customers in the State or \$500,000 for  
13 an electric utility that serves less than 3,000,000  
14 customers but more than 500,000 customers in the State  
15 as of the last day of the quarterly reporting period,  
16 as well as a summary description of each investment  
17 category;

18 (C) A list of the projects which the electric  
19 utility has identified by a unique investment tracking  
20 number for utility plant placed in service during the  
21 prior quarter for utility plant placed in service with  
22 a total dollar value as of the last day of the  
23 quarterly reporting period that is equal to or greater  
24 than \$2,000,000 for an electric utility that serves  
25 more than 3,000,000 customers in the State or \$500,000  
26 for an electric utility that serves less than

1           3,000,000 retail customers but more than \$500,000  
2           retail customers in the State, as well as a summary of  
3           each project;

4           (D) The estimated total dollar value of the  
5           additions to utility plant projected to be placed in  
6           service through the end of the calendar year in which  
7           the report is filed;

8           (E) A list of the major investment categories the  
9           electric utility used to manage its routine standing  
10          operational activities with utility plant projected to  
11          be placed in service through the end of the calendar  
12          year in which the report is filed, including the total  
13          dollar amount for the work reflected in each  
14          investment category in which utility plant in service  
15          is projected to be equal to or greater than \$2,000,000  
16          for an electric utility that serves more than  
17          3,000,000 customers in the State or \$500,000 for an  
18          electric utility that serves less than 3,000,000  
19          retail customers but more than 500,000 retail  
20          customers in the State, as well as a summary  
21          description of each investment category; and

22          (F) A list of the projects for which the electric  
23          utility has identified by a unique investment tracking  
24          number for utility plant projected to be placed in  
25          service through the end of the calendar year in which  
26          the report is filed with an estimated dollar value

1           that is equal to or greater than \$2,000,000 for an  
2           electric utility that serves more than 3,000,000  
3           customers in the State or \$500,000 for an electric  
4           utility that serves less than 3,000,000 retails  
5           customers but more than \$500,000 retail customers in  
6           the State, as well as a summary description of each  
7           project.

8           (6) As part of the Annual Performance Adjustment, the  
9           electric utility shall submit evidence sufficient to  
10          support a determination of its actual revenue requirement  
11          for the applicable calendar year, consistent with the  
12          provisions of paragraphs (d) and (f) of this subsection.  
13          The electric utility shall bear the burden of  
14          demonstrating that its costs were prudent and reasonable,  
15          subject to the provisions of paragraph (4) of this  
16          subsection (f). The Commission's review of the electric  
17          utility's annual adjustment shall be based on the same  
18          evidentiary standards, including, but not limited to,  
19          those concerning the prudence and reasonableness of the  
20          known and measurable costs forecasted to be incurred by  
21          the utility, and the used and usefulness of the actual  
22          plant investment pursuant to Section 9-211 of this Act,  
23          that the Commission applies in a proceeding to review a  
24          filing for changes in rates pursuant to Section 9-201 of  
25          this Act. The Commission shall determine the prudence and  
26          reasonableness of the actual costs incurred by the utility

1 during the applicable calendar year, as well as determine  
2 the original cost of plant in service as of the end of the  
3 applicable calendar year. The Commission shall then  
4 determine the Annual Adjustment, which shall mean the  
5 amount by which, the electric utility's actual revenue  
6 requirement for the applicable year of the Multi-Year Rate  
7 Plan either exceeded, or was exceeded by, the revenue  
8 requirement approved by the Commission for such calendar  
9 year, plus carrying costs calculated at the weighted  
10 average cost of capital approved for the Multi-Year Rate  
11 Plan.

12 The Commission's determination of the electric  
13 utility's actual revenue requirement for the applicable  
14 calendar year shall be based on:

15 (A) the Commission-approved used and useful,  
16 prudent and reasonable actual costs for the applicable  
17 calendar year, which shall be determined pursuant to  
18 the following criteria:

19 (i) the overall level of actual costs incurred  
20 during the calendar year, provided that the  
21 Commission may not allow recovery of actual costs  
22 that are more than 105% of the approved revenue  
23 requirement calculated as provided in item (ii) of  
24 this subparagraph (A), except to the extent the  
25 Commission approves a modification of the  
26 Multi-Year Rate Plan to permit such recovery;

1           (ii) the calculation of 105% of the revenue  
2           requirement required by this subparagraph (A)  
3           shall exclude the revenue requirement impacts of  
4           the following volatile and fluctuating variables  
5           that occurred during the year: (i) storms and  
6           weather-related events for which the utility  
7           provides sufficient evidence to demonstrate that  
8           such expenses were not foreseeable and not in  
9           control of the utility; (ii) new business; (iii)  
10          changes in interest rates; (iv) changes in taxes;  
11          (v) facility relocations; (vi) changes in pension  
12          or post-retirement benefits costs due to  
13          fluctuations in interest rates, market returns or  
14          actuarial assumptions; (vii) amortization expenses  
15          related to costs; and (viii) changes in the timing  
16          of when an expenditure or investment is made such  
17          that it is accelerated to occur during the  
18          applicable year or deferred to occur in a  
19          subsequent year;

20          (B) the year-end rate base;

21          (C) the cost of equity approved in the multi-year  
22          rate plan; and

23          (D) the electric utility's actual year-end capital  
24          structure, provided that the common equity ratio in  
25          such capital structure may not exceed the common  
26          equity ratio that was approved by the Commission in

1           the Multi-Year Rate Plan.

2           (2) The Commission's determinations of the prudence  
3           and reasonableness of the costs incurred for the  
4           applicable year, and of the original cost of plant in  
5           service as of the end of the applicable calendar year,  
6           shall be final upon entry of the Commission's order and  
7           shall not be subject to collateral attack in any other  
8           Commission proceeding, case, docket, order, rule, or  
9           regulation; however, nothing in this Section shall  
10          prohibit a party from petitioning the Commission to rehear  
11          or appeal to the courts the order pursuant to the  
12          provisions of this Act.

13          (g) During the period leading to approval of the first  
14          Multi-Year Integrated Grid Plan, each electric utility will  
15          necessarily continue to invest in its distribution grid. Those  
16          investments will be subject to a determination of prudence and  
17          reasonableness consistent with Commission practice and law.  
18          Any failure to conform to the Multi-Year Integrated Grid Plan  
19          ultimately approved shall not imply imprudence or  
20          unreasonableness.

21          (h) After calculating the Performance Adjustment and  
22          Annual Adjustment, the Commission shall order the electric  
23          utility to collect the amount in excess of the revenue  
24          requirement from customers, or issue a refund to customers, as  
25          applicable, to be applied through a surcharge beginning with  
26          the next calendar year.

1 Electric utilities subject to the requirements of this  
2 Section shall be permitted to file new or revised tariffs to  
3 comply with the provisions of, and Commission orders entered  
4 pursuant to, this Section.

5 (Source: P.A. 104-417, eff. 8-15-25; revised 12-12-25.)

6 Section 15. The Environmental Protection Act is amended by  
7 changing Section 9.15 as follows:

8 (415 ILCS 5/9.15)

9 (Text of Section before amendment by P.A. 104-458)

10 Sec. 9.15. Greenhouse gases.

11 (a) An air pollution construction permit shall not be  
12 required due to emissions of greenhouse gases if the  
13 equipment, site, or source is not subject to regulation, as  
14 defined by 40 CFR 52.21, as now or hereafter amended, for  
15 greenhouse gases or is otherwise not addressed in this Section  
16 or by the Board in regulations for greenhouse gases. These  
17 exemptions do not relieve an owner or operator from the  
18 obligation to comply with other applicable rules or  
19 regulations.

20 (b) An air pollution operating permit shall not be  
21 required due to emissions of greenhouse gases if the  
22 equipment, site, or source is not subject to regulation, as  
23 defined by Section 39.5 of this Act, for greenhouse gases or is  
24 otherwise not addressed in this Section or by the Board in

1 regulations for greenhouse gases. These exemptions do not  
2 relieve an owner or operator from the obligation to comply  
3 with other applicable rules or regulations.

4 (c) (Blank).

5 (d) (Blank).

6 (e) (Blank).

7 (f) As used in this Section:

8 "Carbon dioxide emission" means the plant annual CO<sub>2</sub> total  
9 output emission as measured by the United States Environmental  
10 Protection Agency in its Emissions & Generation Resource  
11 Integrated Database (eGrid), or its successor.

12 "Carbon dioxide equivalent emissions" or "CO<sub>2</sub>e" means the  
13 sum total of the mass amount of emissions in tons per year,  
14 calculated by multiplying the mass amount of each of the 6  
15 greenhouse gases specified in Section 3.207, in tons per year,  
16 by its associated global warming potential as set forth in 40  
17 CFR 98, subpart A, table A-1 or its successor, and then adding  
18 them all together.

19 "Cogeneration" or "combined heat and power" refers to any  
20 system that, either simultaneously or sequentially, produces  
21 electricity and useful thermal energy from a single fuel  
22 source.

23 "Copollutants" refers to the 6 criteria pollutants that  
24 have been identified by the United States Environmental  
25 Protection Agency pursuant to the Clean Air Act.

26 "Electric generating unit" or "EGU" means a fossil

1 fuel-fired stationary boiler, combustion turbine, or combined  
2 cycle system that serves a generator that has a nameplate  
3 capacity greater than 25 MWe and produces electricity for  
4 sale.

5 "Environmental justice community" means the definition of  
6 that term based on existing methodologies and findings, used  
7 and as may be updated by the Illinois Power Agency and its  
8 program administrator in the Illinois Solar for All Program.

9 "Equity investment eligible community" or "eligible  
10 community" means the geographic areas throughout Illinois that  
11 would most benefit from equitable investments by the State  
12 designed to combat discrimination and foster sustainable  
13 economic growth. Specifically, eligible community means the  
14 following areas:

15 (1) areas where residents have been historically  
16 excluded from economic opportunities, including  
17 opportunities in the energy sector, as defined as R3 areas  
18 pursuant to Section 10-40 of the Cannabis Regulation and  
19 Tax Act; and

20 (2) areas where residents have been historically  
21 subject to disproportionate burdens of pollution,  
22 including pollution from the energy sector, as established  
23 by environmental justice communities as defined by the  
24 Illinois Power Agency pursuant to the Illinois Power  
25 Agency Act, excluding any racial or ethnic indicators.

26 "Equity investment eligible person" or "eligible person"

1 means the persons who would most benefit from equitable  
2 investments by the State designed to combat discrimination and  
3 foster sustainable economic growth. Specifically, eligible  
4 person means the following people:

5 (1) persons whose primary residence is in an equity  
6 investment eligible community;

7 (2) persons whose primary residence is in a  
8 municipality, or a county with a population under 100,000,  
9 where the closure of an electric generating unit or mine  
10 has been publicly announced or the electric generating  
11 unit or mine is in the process of closing or closed within  
12 the last 5 years;

13 (3) persons who are graduates of or currently enrolled  
14 in the foster care system; or

15 (4) persons who were formerly incarcerated.

16 "Existing emissions" means:

17 (1) for CO<sub>2</sub>e, the total average tons-per-year of CO<sub>2</sub>e  
18 emitted by the EGU or large GHG-emitting unit either in  
19 the years 2018 through 2020 or, if the unit was not yet in  
20 operation by January 1, 2018, in the first 3 full years of  
21 that unit's operation; and

22 (2) for any copollutant, the total average  
23 tons-per-year of that copollutant emitted by the EGU or  
24 large GHG-emitting unit either in the years 2018 through  
25 2020 or, if the unit was not yet in operation by January 1,  
26 2018, in the first 3 full years of that unit's operation.

1 "Green hydrogen" means a power plant technology in which  
2 an EGU creates electric power exclusively from electrolytic  
3 hydrogen, in a manner that produces zero carbon and  
4 copollutant emissions, using hydrogen fuel that is  
5 electrolyzed using a 100% renewable zero carbon emission  
6 energy source.

7 "Large greenhouse gas-emitting unit" or "large  
8 GHG-emitting unit" means a unit that is an electric generating  
9 unit or other fossil fuel-fired unit that itself has a  
10 nameplate capacity or serves a generator that has a nameplate  
11 capacity greater than 25 MWe and that produces electricity,  
12 including, but not limited to, coal-fired, coal-derived,  
13 oil-fired, natural gas-fired, and cogeneration units.

14 "NO<sub>x</sub> emission rate" means the plant annual NO<sub>x</sub> total output  
15 emission rate as measured by the United States Environmental  
16 Protection Agency in its Emissions & Generation Resource  
17 Integrated Database (eGrid), or its successor, in the most  
18 recent year for which data is available.

19 "Public greenhouse gas-emitting units" or "public  
20 GHG-emitting unit" means large greenhouse gas-emitting units,  
21 including EGUs, that are wholly owned, directly or indirectly,  
22 by one or more municipalities, municipal corporations, joint  
23 municipal electric power agencies, electric cooperatives, or  
24 other governmental or nonprofit entities, whether organized  
25 and created under the laws of Illinois or another state.

26 "SO<sub>2</sub> emission rate" means the "plant annual SO<sub>2</sub> total

1 output emission rate" as measured by the United States  
2 Environmental Protection Agency in its Emissions & Generation  
3 Resource Integrated Database (eGrid), or its successor, in the  
4 most recent year for which data is available.

5 (g) All EGUs and large greenhouse gas-emitting units that  
6 use coal or oil as a fuel and are not public GHG-emitting units  
7 shall permanently reduce all CO<sub>2</sub>e and copollutant emissions to  
8 zero no later than January 1, 2030.

9 (h) All EGUs and large greenhouse gas-emitting units that  
10 use coal as a fuel and are public GHG-emitting units shall  
11 permanently reduce CO<sub>2</sub>e emissions to zero no later than  
12 December 31, 2045. Any source or plant with such units must  
13 also reduce their CO<sub>2</sub>e emissions by 45% from existing  
14 emissions by no later than January 1, 2035. If the emissions  
15 reduction requirement is not achieved by December 31, 2035,  
16 the plant shall retire one or more units or otherwise reduce  
17 its CO<sub>2</sub>e emissions by 45% from existing emissions by June 30,  
18 2038.

19 (i) All EGUs and large greenhouse gas-emitting units that  
20 use gas as a fuel and are not public GHG-emitting units shall  
21 permanently reduce all CO<sub>2</sub>e and copollutant emissions to zero,  
22 including through unit retirement or the use of 100% green  
23 hydrogen or other similar technology that is commercially  
24 proven to achieve zero carbon emissions, according to the  
25 following:

26 (1) No later than January 1, 2030: all EGUs and large

1 greenhouse gas-emitting units that have a NO<sub>x</sub> emissions  
2 rate of greater than 0.12 lbs/MWh or a SO<sub>2</sub> emission rate of  
3 greater than 0.006 lb/MWh, and are located in or within 3  
4 miles of an environmental justice community designated as  
5 of January 1, 2021 or an equity investment eligible  
6 community.

7 (2) No later than January 1, 2040: all EGUs and large  
8 greenhouse gas-emitting units that have a NO<sub>x</sub> emission  
9 rate of greater than 0.12 lbs/MWh or a SO<sub>2</sub> emission rate  
10 greater than 0.006 lb/MWh, and are not located in or  
11 within 3 miles of an environmental justice community  
12 designated as of January 1, 2021 or an equity investment  
13 eligible community. After January 1, 2035, each such EGU  
14 and large greenhouse gas-emitting unit shall reduce its  
15 CO<sub>2</sub>e emissions by at least 50% from its existing emissions  
16 for CO<sub>2</sub>e, and shall be limited in operation to, on average,  
17 6 hours or less per day, measured over a calendar year, and  
18 shall not run for more than 24 consecutive hours except in  
19 emergency conditions, as designated by a Regional  
20 Transmission Organization or Independent System Operator.

21 (3) No later than January 1, 2035: all EGUs and large  
22 greenhouse gas-emitting units that began operation prior  
23 to the effective date of this amendatory Act of the 102nd  
24 General Assembly and have a NO<sub>x</sub> emission rate of less than  
25 or equal to 0.12 lb/MWh and a SO<sub>2</sub> emission rate less than  
26 or equal to 0.006 lb/MWh, and are located in or within 3

1 miles of an environmental justice community designated as  
2 of January 1, 2021 or an equity investment eligible  
3 community. Each such EGU and large greenhouse gas-emitting  
4 unit shall reduce its CO<sub>2</sub>e emissions by at least 50% from  
5 its existing emissions for CO<sub>2</sub>e no later than January 1,  
6 2030.

7 (4) No later than January 1, 2040: All remaining EGUs  
8 and large greenhouse gas-emitting units that have a heat  
9 rate greater than or equal to 7000 BTU/kWh. Each such EGU  
10 and Large greenhouse gas-emitting unit shall reduce its  
11 CO<sub>2</sub>e emissions by at least 50% from its existing emissions  
12 for CO<sub>2</sub>e no later than January 1, 2035.

13 (5) No later than January 1, 2045: all remaining EGUs  
14 and large greenhouse gas-emitting units.

15 (j) All EGUs and large greenhouse gas-emitting units that  
16 use gas as a fuel and are public GHG-emitting units shall  
17 permanently reduce all CO<sub>2</sub>e and copollutant emissions to zero,  
18 including through unit retirement or the use of 100% green  
19 hydrogen or other similar technology that is commercially  
20 proven to achieve zero carbon emissions by January 1, 2045.

21 (k) All EGUs and large greenhouse gas-emitting units that  
22 utilize combined heat and power or cogeneration technology  
23 shall permanently reduce all CO<sub>2</sub>e and copollutant emissions to  
24 zero, including through unit retirement or the use of 100%  
25 green hydrogen or other similar technology that is  
26 commercially proven to achieve zero carbon emissions by

1 January 1, 2045.

2 (k-5) No EGU or large greenhouse gas-emitting unit that  
3 uses gas as a fuel and is not a public GHG-emitting unit may  
4 emit, in any 12-month period, CO<sub>2</sub>e or copollutants in excess of  
5 that unit's existing emissions for those pollutants.

6 (1) Notwithstanding subsections (g) through (k-5), large  
7 GHG-emitting units including EGUs may temporarily continue  
8 emitting CO<sub>2</sub>e and copollutants after any applicable deadline  
9 specified in any of subsections (g) through (k-5) if it has  
10 been determined, as described in paragraphs (1) and (2) of  
11 this subsection, that ongoing operation of the EGU is  
12 necessary to maintain power grid supply and reliability or  
13 ongoing operation of large GHG-emitting unit that is not an  
14 EGU is necessary to serve as an emergency backup to  
15 operations. Up to and including the occurrence of an emission  
16 reduction deadline under subsection (i), all EGUs and large  
17 GHG-emitting units must comply with the following terms:

18 (1) if an EGU or large GHG-emitting unit that is a  
19 participant in a regional transmission organization  
20 intends to retire, it must submit documentation to the  
21 appropriate regional transmission organization by the  
22 appropriate deadline that meets all applicable regulatory  
23 requirements necessary to obtain approval to permanently  
24 cease operating the large GHG-emitting unit;

25 (2) if any EGU or large GHG-emitting unit that is a  
26 participant in a regional transmission organization

1 receives notice that the regional transmission  
2 organization has determined that continued operation of  
3 the unit is required, the unit may continue operating  
4 until the issue identified by the regional transmission  
5 organization is resolved. The owner or operator of the  
6 unit must cooperate with the regional transmission  
7 organization in resolving the issue and must reduce its  
8 emissions to zero, consistent with the requirements under  
9 subsection (g), (h), (i), (j), (k), or (k-5), as  
10 applicable, as soon as practicable when the issue  
11 identified by the regional transmission organization is  
12 resolved; and

13 (3) any large GHG-emitting unit that is not a  
14 participant in a regional transmission organization shall  
15 be allowed to continue emitting CO<sub>2</sub>e and copollutants  
16 after the zero-emission date specified in subsection (g),  
17 (h), (i), (j), (k), or (k-5), as applicable, in the  
18 capacity of an emergency backup unit if approved by the  
19 Illinois Commerce Commission.

20 (m) No variance, adjusted standard, or other regulatory  
21 relief otherwise available in this Act may be granted to the  
22 emissions reduction and elimination obligations in this  
23 Section.

24 (n) By June 30 of each year, beginning in 2025, the Agency  
25 shall prepare and publish on its website a report setting  
26 forth the actual greenhouse gas emissions from individual

1 units and the aggregate statewide emissions from all units for  
2 the prior year.

3 (o) Every 5 years beginning in 2025, the Environmental  
4 Protection Agency, Illinois Power Agency, and Illinois  
5 Commerce Commission shall jointly prepare, and release  
6 publicly, a report to the General Assembly that examines the  
7 State's current progress toward its renewable energy resource  
8 development goals, the status of CO<sub>2</sub>e and copollutant  
9 emissions reductions, the current status and progress toward  
10 developing and implementing green hydrogen technologies, the  
11 current and projected status of electric resource adequacy and  
12 reliability throughout the State for the period beginning 5  
13 years ahead, and proposed solutions for any findings. The  
14 Environmental Protection Agency, Illinois Power Agency, and  
15 Illinois Commerce Commission shall consult PJM  
16 Interconnection, LLC and Midcontinent Independent System  
17 Operator, Inc., or their respective successor organizations  
18 regarding forecasted resource adequacy and reliability needs,  
19 anticipated new generation interconnection, new transmission  
20 development or upgrades, and any announced large GHG-emitting  
21 unit closure dates and include this information in the report.  
22 The report shall be released publicly by no later than  
23 December 15 of the year it is prepared. If the Environmental  
24 Protection Agency, Illinois Power Agency, and Illinois  
25 Commerce Commission jointly conclude in the report that the  
26 data from the regional grid operators, the pace of renewable

1 energy development, the pace of development of energy storage  
2 and demand response utilization, transmission capacity, and  
3 the CO<sub>2</sub>e and copollutant emissions reductions required by  
4 subsection (i) or (k-5) reasonably demonstrate that a resource  
5 adequacy shortfall will occur, including whether there will be  
6 sufficient in-state capacity to meet the zonal requirements of  
7 MISO Zone 4 or the PJM ComEd Zone, per the requirements of the  
8 regional transmission organizations, or that the regional  
9 transmission operators determine that a reliability violation  
10 will occur during the time frame the study is evaluating, then  
11 the Illinois Power Agency, in conjunction with the  
12 Environmental Protection Agency shall develop a plan to reduce  
13 or delay CO<sub>2</sub>e and copollutant emissions reductions  
14 requirements only to the extent and for the duration necessary  
15 to meet the resource adequacy and reliability needs of the  
16 State, including allowing any plants whose emission reduction  
17 deadline has been identified in the plan as creating a  
18 reliability concern to continue operating, including operating  
19 with reduced emissions or as emergency backup where  
20 appropriate. The plan shall also consider the use of renewable  
21 energy, energy storage, demand response, transmission  
22 development, or other strategies to resolve the identified  
23 resource adequacy shortfall or reliability violation.

24 (1) In developing the plan, the Environmental  
25 Protection Agency and the Illinois Power Agency shall hold  
26 at least one workshop open to, and accessible at a time and

1 place convenient to, the public and shall consider any  
2 comments made by stakeholders or the public. Upon  
3 development of the plan, copies of the plan shall be  
4 posted and made publicly available on the Environmental  
5 Protection Agency's, the Illinois Power Agency's, and the  
6 Illinois Commerce Commission's websites. All interested  
7 parties shall have 60 days following the date of posting  
8 to provide comment to the Environmental Protection Agency  
9 and the Illinois Power Agency on the plan. All comments  
10 submitted to the Environmental Protection Agency and the  
11 Illinois Power Agency shall be encouraged to be specific,  
12 supported by data or other detailed analyses, and, if  
13 objecting to all or a portion of the plan, accompanied by  
14 specific alternative wording or proposals. All comments  
15 shall be posted on the Environmental Protection Agency's,  
16 the Illinois Power Agency's, and the Illinois Commerce  
17 Commission's websites. Within 30 days following the end of  
18 the 60-day review period, the Environmental Protection  
19 Agency and the Illinois Power Agency shall revise the plan  
20 as necessary based on the comments received and file its  
21 revised plan with the Illinois Commerce Commission for  
22 approval.

23 (2) Within 60 days after the filing of the revised  
24 plan at the Illinois Commerce Commission, any person  
25 objecting to the plan shall file an objection with the  
26 Illinois Commerce Commission. Within 30 days after the

1 expiration of the comment period, the Illinois Commerce  
2 Commission shall determine whether an evidentiary hearing  
3 is necessary. The Illinois Commerce Commission shall also  
4 host 3 public hearings within 90 days after the plan is  
5 filed. Following the evidentiary and public hearings, the  
6 Illinois Commerce Commission shall enter its order  
7 approving or approving with modifications the reliability  
8 mitigation plan within 180 days.

9 (3) The Illinois Commerce Commission shall only  
10 approve the plan if the Illinois Commerce Commission  
11 determines that it will resolve the resource adequacy or  
12 reliability deficiency identified in the reliability  
13 mitigation plan at the least amount of CO<sub>2</sub>e and copollutant  
14 emissions, taking into consideration the emissions impacts  
15 on environmental justice communities, and that it will  
16 ensure adequate, reliable, affordable, efficient, and  
17 environmentally sustainable electric service at the lowest  
18 total cost over time, taking into account the impact of  
19 increases in emissions.

20 (4) If the resource adequacy or reliability deficiency  
21 identified in the reliability mitigation plan is resolved  
22 or reduced, the Environmental Protection Agency and the  
23 Illinois Power Agency may file an amended plan adjusting  
24 the reduction or delay in CO<sub>2</sub>e and copollutant emission  
25 reduction requirements identified in the plan.

26 (Source: P.A. 102-662, eff. 9-15-21; 102-1031, eff. 5-27-22.)

1 (Text of Section after amendment by P.A. 104-458)

2 Sec. 9.15. Greenhouse gases.

3 (a) An air pollution construction permit shall not be  
4 required due to emissions of greenhouse gases if the  
5 equipment, site, or source is not subject to regulation, as  
6 defined by 40 CFR 52.21, as now or hereafter amended, for  
7 greenhouse gases or is otherwise not addressed in this Section  
8 or by the Board in regulations for greenhouse gases. These  
9 exemptions do not relieve an owner or operator from the  
10 obligation to comply with other applicable rules or  
11 regulations.

12 (b) An air pollution operating permit shall not be  
13 required due to emissions of greenhouse gases if the  
14 equipment, site, or source is not subject to regulation, as  
15 defined by Section 39.5 of this Act, for greenhouse gases or is  
16 otherwise not addressed in this Section or by the Board in  
17 regulations for greenhouse gases. These exemptions do not  
18 relieve an owner or operator from the obligation to comply  
19 with other applicable rules or regulations.

20 (c) (Blank).

21 (d) (Blank).

22 (e) (Blank).

23 (f) As used in this Section:

24 "Carbon dioxide emission" means the plant annual CO<sub>2</sub> total  
25 output emission as measured by the United States Environmental

1 Protection Agency in its Emissions & Generation Resource  
2 Integrated Database (eGrid), or its successor.

3 "Carbon dioxide equivalent emissions" or "CO<sub>2</sub>e" means the  
4 sum total of the mass amount of emissions in tons per year,  
5 calculated by multiplying the mass amount of each of the 6  
6 greenhouse gases specified in Section 3.207, in tons per year,  
7 by its associated global warming potential as set forth in 40  
8 CFR 98, subpart A, table A-1 or its successor, and then adding  
9 them all together.

10 "Cogeneration" or "combined heat and power" refers to any  
11 system that, either simultaneously or sequentially, produces  
12 electricity and useful thermal energy from a single fuel  
13 source.

14 "Copollutants" refers to the 6 criteria pollutants that  
15 have been identified by the United States Environmental  
16 Protection Agency pursuant to the Clean Air Act.

17 "Electric generating unit" or "EGU" means a fossil  
18 fuel-fired stationary boiler, combustion turbine, or combined  
19 cycle system that serves a generator that has a nameplate  
20 capacity greater than 25 MWe and produces electricity for  
21 sale.

22 "Environmental justice community" means the definition of  
23 that term based on existing methodologies and findings, used  
24 and as may be updated by the Illinois Power Agency and its  
25 program administrator in the Illinois Solar for All Program.

26 "Equity investment eligible community" or "eligible

1 community" means the geographic areas throughout Illinois that  
2 would most benefit from equitable investments by the State  
3 designed to combat discrimination and foster sustainable  
4 economic growth. Specifically, eligible community means the  
5 following areas:

6 (1) areas where residents have been historically  
7 excluded from economic opportunities, including  
8 opportunities in the energy sector, as defined as R3 areas  
9 pursuant to Section 10-40 of the Cannabis Regulation and  
10 Tax Act; and

11 (2) areas where residents have been historically  
12 subject to disproportionate burdens of pollution,  
13 including pollution from the energy sector, as established  
14 by environmental justice communities as defined by the  
15 Illinois Power Agency pursuant to the Illinois Power  
16 Agency Act, excluding any racial or ethnic indicators.

17 "Equity investment eligible person" or "eligible person"  
18 means the persons who would most benefit from equitable  
19 investments by the State designed to combat discrimination and  
20 foster sustainable economic growth. Specifically, eligible  
21 person means the following people:

22 (1) persons whose primary residence is in an equity  
23 investment eligible community;

24 (2) persons whose primary residence is in a  
25 municipality, or a county with a population under 100,000,  
26 where the closure of an electric generating unit or mine

1 has been publicly announced or the electric generating  
2 unit or mine is in the process of closing or closed within  
3 the last 5 years;

4 (3) persons who are graduates of or currently enrolled  
5 in the foster care system; or

6 (4) persons who were formerly incarcerated.

7 "Existing emissions" means:

8 (1) for CO<sub>2</sub>e, the total average tons-per-year of CO<sub>2</sub>e  
9 emitted by the EGU or large GHG-emitting unit either in  
10 the years 2018 through 2020 or, if the unit was not yet in  
11 operation by January 1, 2018, in the first 3 full years of  
12 that unit's operation; and

13 (2) for any copollutant, the total average  
14 tons-per-year of that copollutant emitted by the EGU or  
15 large GHG-emitting unit either in the years 2018 through  
16 2020 or, if the unit was not yet in operation by January 1,  
17 2018, in the first 3 full years of that unit's operation.

18 "Green hydrogen" means a power plant technology in which  
19 an EGU creates electric power exclusively from electrolytic  
20 hydrogen, in a manner that produces zero carbon and  
21 copollutant emissions, using hydrogen fuel that is  
22 electrolyzed using a 100% renewable zero carbon emission  
23 energy source.

24 "Large greenhouse gas-emitting unit" or "large  
25 GHG-emitting unit" means a unit that is an electric generating  
26 unit or other fossil fuel-fired unit that itself has a

1 nameplate capacity or serves a generator that has a nameplate  
2 capacity greater than 25 MWe and that produces electricity,  
3 including, but not limited to, coal-fired, coal-derived,  
4 oil-fired, natural gas-fired, and cogeneration units.

5 "NO<sub>x</sub> emission rate" means the plant annual NO<sub>x</sub> total output  
6 emission rate as measured by the United States Environmental  
7 Protection Agency in its Emissions & Generation Resource  
8 Integrated Database (eGrid), or its successor, in the most  
9 recent year for which data is available.

10 "Public greenhouse gas-emitting units" or "public  
11 GHG-emitting unit" means large greenhouse gas-emitting units,  
12 including EGUs, that are wholly owned, directly or indirectly,  
13 by one or more municipalities, municipal corporations, joint  
14 municipal electric power agencies, electric cooperatives, or  
15 other governmental or nonprofit entities, whether organized  
16 and created under the laws of Illinois or another state.

17 "SO<sub>2</sub> emission rate" means the "plant annual SO<sub>2</sub> total  
18 output emission rate" as measured by the United States  
19 Environmental Protection Agency in its Emissions & Generation  
20 Resource Integrated Database (eGrid), or its successor, in the  
21 most recent year for which data is available.

22 (g) All EGUs and large greenhouse gas-emitting units that  
23 use coal or oil as a fuel and are not public GHG-emitting units  
24 shall permanently reduce all CO<sub>2</sub>e and copollutant emissions to  
25 zero no later than January 1, 2040, or earlier if certified by  
26 the Illinois Commerce Commission as cost-effective under a

1 market-driven analysis under Section Public Utilities Act  
2 2030.

3 (h) All EGUs and large greenhouse gas-emitting units that  
4 use coal as a fuel and are public GHG-emitting units shall  
5 permanently reduce CO<sub>2</sub>e emissions to zero no later than  
6 December 31, 2055, or earlier if certified by the Illinois  
7 Commerce Commission as cost-effective under a market-driven  
8 analysis analysis under Section Public Utilities Act 2045. Any  
9 source or plant with such units must also reduce their CO<sub>2</sub>e  
10 emissions by 45% from existing emissions by no later than  
11 January 1, 2035. If the emissions reduction requirement is not  
12 achieved by December 31, 2045, or earlier if certified by the  
13 Illinois Commerce Commission as cost-effective under a  
14 market-driven analysis panalysis under Section Public  
15 Utilities Act 2035, the plant shall retire one or more units or  
16 otherwise reduce its CO<sub>2</sub>e emissions by 45% from existing  
17 emissions by June 30, 2048 ~~2038~~.

18 (i) All EGUs and large greenhouse gas-emitting units that  
19 use gas as a fuel and are not public GHG-emitting units shall  
20 permanently reduce all CO<sub>2</sub>e and copollutant emissions to zero,  
21 including through unit retirement or the use of 100% green  
22 hydrogen or other similar technology that is commercially  
23 proven to achieve zero carbon emissions, according to the  
24 following:

25 (1) No later than January 1, 2030: all EGUs and large  
26 greenhouse gas-emitting units that have a NO<sub>x</sub> emissions

1 rate of greater than 0.12 lbs/MWh or a SO<sub>2</sub> emission rate of  
2 greater than 0.006 lb/MWh, and are located in or within 3  
3 miles of an environmental justice community designated as  
4 of January 1, 2021 or an equity investment eligible  
5 community.

6 (2) No later than January 1, 2050 or earlier if  
7 certified by the Illinois Commerce Commission as  
8 cost-effective under a market-driven analysis analysis  
9 under Section Public Utilities Act ~~2040~~: all EGUs and  
10 large greenhouse gas-emitting units that have a NO<sub>x</sub>  
11 emission rate of greater than 0.12 lbs/MWh or a SO<sub>2</sub>  
12 emission rate greater than 0.006 lb/MWh, and are not  
13 located in or within 3 miles of an environmental justice  
14 community designated as of January 1, 2021 or an equity  
15 investment eligible community. After January 1, 2035, each  
16 such EGU and large greenhouse gas-emitting unit shall  
17 reduce its CO<sub>2</sub>e emissions by at least 50% from its existing  
18 emissions for CO<sub>2</sub>e, and shall be limited in operation to,  
19 on average, 6 hours or less per day, measured over a  
20 calendar year, and shall not run for more than 24  
21 consecutive hours except in emergency conditions, as  
22 designated by a Regional Transmission Organization or  
23 Independent System Operator.

24 (3) No later than January 1, 2035: all EGUs and large  
25 greenhouse gas-emitting units that began operation prior  
26 to the effective date of this amendatory Act of the 102nd

1 General Assembly and have a NO<sub>x</sub> emission rate of less than  
2 or equal to 0.12 lb/MWh and a SO<sub>2</sub> emission rate less than  
3 or equal to 0.006 lb/MWh, and are located in or within 3  
4 miles of an environmental justice community designated as  
5 of January 1, 2021 or an equity investment eligible  
6 community. Each such EGU and large greenhouse gas-emitting  
7 unit shall reduce its CO<sub>2</sub>e emissions by at least 50% from  
8 its existing emissions for CO<sub>2</sub>e no later than January 1,  
9 2030.

10 (4) No later than January 1, 2040: All remaining EGUs  
11 and large greenhouse gas-emitting units that have a heat  
12 rate greater than or equal to 7000 BTU/kWh. Each such EGU  
13 and Large greenhouse gas-emitting unit shall reduce its  
14 CO<sub>2</sub>e emissions by at least 50% from its existing emissions  
15 for CO<sub>2</sub>e no later than January 1, 2035.

16 (5) No later than January 1, 2055 or earlier if  
17 certified by the Illinois Commerce Commission as  
18 cost-effective under a market-driven analysis analysis  
19 under Section Public Utilities Act ~~2045~~: all remaining  
20 EGUs and large greenhouse gas-emitting units.

21 (j) All EGUs and large greenhouse gas-emitting units that  
22 use gas as a fuel and are public GHG-emitting units shall  
23 permanently reduce all CO<sub>2</sub>e and copollutant emissions to zero,  
24 including through unit retirement or the use of 100% green  
25 hydrogen or other similar technology that is commercially  
26 proven to achieve zero carbon emissions by January 1, 2045.

1 (k) All EGUs and large greenhouse gas-emitting units that  
2 utilize combined heat and power or cogeneration technology  
3 shall permanently reduce all CO<sub>2</sub>e and copollutant emissions to  
4 zero, including through unit retirement or the use of 100%  
5 green hydrogen or other similar technology that is  
6 commercially proven to achieve zero carbon emissions by  
7 January 1, 2045.

8 (k-5) No EGU or large greenhouse gas-emitting unit that  
9 uses gas as a fuel and is not a public GHG-emitting unit may  
10 emit, in any 12-month period, CO<sub>2</sub>e or copollutants in excess of  
11 that unit's existing emissions for those pollutants.

12 (l) Notwithstanding subsections (g) through (k-5), large  
13 GHG-emitting units including EGUs may temporarily continue  
14 emitting CO<sub>2</sub>e and copollutants after any applicable deadline  
15 specified in any of subsections (g) through (k-5) if it has  
16 been determined, as described in paragraphs (1) and (2) of  
17 this subsection, that ongoing operation of the EGU is  
18 necessary to maintain power grid supply and reliability or  
19 ongoing operation of large GHG-emitting unit that is not an  
20 EGU is necessary to serve as an emergency backup to  
21 operations. Up to and including the occurrence of an emission  
22 reduction deadline under subsection (i), all EGUs and large  
23 GHG-emitting units must comply with the following terms:

24 (1) if an EGU or large GHG-emitting unit that is a  
25 participant in a regional transmission organization  
26 intends to retire, it must submit documentation to the

1 appropriate regional transmission organization by the  
2 appropriate deadline that meets all applicable regulatory  
3 requirements necessary to obtain approval to permanently  
4 cease operating the large GHG-emitting unit;

5 (2) if any EGU or large GHG-emitting unit that is a  
6 participant in a regional transmission organization  
7 receives notice that the regional transmission  
8 organization has determined that continued operation of  
9 the unit is required, the unit may continue operating  
10 until the issue identified by the regional transmission  
11 organization is resolved. The owner or operator of the  
12 unit must cooperate with the regional transmission  
13 organization in resolving the issue and must reduce its  
14 emissions to zero, consistent with the requirements under  
15 subsection (g), (h), (i), (j), (k), or (k-5), as  
16 applicable, as soon as practicable when the issue  
17 identified by the regional transmission organization is  
18 resolved; and

19 (3) any large GHG-emitting unit that is not a  
20 participant in a regional transmission organization shall  
21 be allowed to continue emitting CO<sub>2</sub>e and copollutants  
22 after the zero-emission date specified in subsection (g),  
23 (h), (i), (j), (k), or (k-5), as applicable, in the  
24 capacity of an emergency backup unit if approved by the  
25 Illinois Commerce Commission.

26 (m) No variance, adjusted standard, or other regulatory

1 relief otherwise available in this Act may be granted to the  
2 emissions reduction and elimination obligations in this  
3 Section.

4 (n) By June 30 of each year, beginning in 2025, the Agency  
5 shall prepare and publish on its website a report setting  
6 forth the actual greenhouse gas emissions from individual  
7 units and the aggregate statewide emissions from all units for  
8 the prior year.

9 (o) The Environmental Protection Agency, Illinois Power  
10 Agency, and Illinois Commerce Commission shall jointly  
11 prepare, and release publicly, a report to the General  
12 Assembly that examines the State's current progress toward its  
13 renewable energy resource development goals, the status of  
14 CO<sub>2</sub>e and copollutant emissions reductions, the current status  
15 and progress toward developing and implementing green hydrogen  
16 technologies, the current and projected status of electric  
17 resource adequacy and reliability throughout the State for the  
18 period beginning 5 years ahead, and proposed solutions for any  
19 findings. The Environmental Protection Agency, Illinois Power  
20 Agency, and Illinois Commerce Commission shall consult PJM  
21 Interconnection, LLC and Midcontinent Independent System  
22 Operator, Inc., or their respective successor organizations  
23 regarding forecasted resource adequacy and reliability needs,  
24 anticipated new generation interconnection, new transmission  
25 development or upgrades, and any announced large GHG-emitting  
26 unit closure dates and include this information in the report.

1 The report shall be released publicly by no later than  
2 December 15 of the year it is prepared. If the Environmental  
3 Protection Agency, Illinois Power Agency, and Illinois  
4 Commerce Commission jointly conclude in the report that the  
5 data from the regional grid operators, the pace of renewable  
6 energy development, the pace of development of energy storage  
7 and demand response utilization, transmission capacity, and  
8 the CO<sub>2</sub>e and copollutant emissions reductions required by  
9 subsection (i) or (k-5) reasonably demonstrate that a resource  
10 adequacy shortfall will occur, including whether there will be  
11 sufficient in-state capacity to meet the zonal requirements of  
12 MISO Zone 4 or the PJM ComEd Zone, per the requirements of the  
13 regional transmission organizations, or that the regional  
14 transmission operators determine that a reliability violation  
15 will occur during the time frame the study is evaluating, then  
16 the Illinois Power Agency, in conjunction with the  
17 Environmental Protection Agency shall develop a plan to reduce  
18 or delay CO<sub>2</sub>e and copollutant emissions reductions  
19 requirements only to the extent and for the duration necessary  
20 to meet the resource adequacy and reliability needs of the  
21 State, including allowing any plants whose emission reduction  
22 deadline has been identified in the plan as creating a  
23 reliability concern to continue operating, including operating  
24 with reduced emissions or as emergency backup where  
25 appropriate. The plan shall also consider the use of renewable  
26 energy, energy storage, demand response, transmission

1 development, or other strategies to resolve the identified  
2 resource adequacy shortfall or reliability violation.

3 (1) In developing the plan, the Environmental  
4 Protection Agency and the Illinois Power Agency shall hold  
5 at least one workshop open to, and accessible at a time and  
6 place convenient to, the public and shall consider any  
7 comments made by stakeholders or the public. Upon  
8 development of the plan, copies of the plan shall be  
9 posted and made publicly available on the Environmental  
10 Protection Agency's, the Illinois Power Agency's, and the  
11 Illinois Commerce Commission's websites. All interested  
12 parties shall have 60 days following the date of posting  
13 to provide comment to the Environmental Protection Agency  
14 and the Illinois Power Agency on the plan. All comments  
15 submitted to the Environmental Protection Agency and the  
16 Illinois Power Agency shall be encouraged to be specific,  
17 supported by data or other detailed analyses, and, if  
18 objecting to all or a portion of the plan, accompanied by  
19 specific alternative wording or proposals. All comments  
20 shall be posted on the Environmental Protection Agency's,  
21 the Illinois Power Agency's, and the Illinois Commerce  
22 Commission's websites. Within 30 days following the end of  
23 the 60-day review period, the Environmental Protection  
24 Agency and the Illinois Power Agency shall revise the plan  
25 as necessary based on the comments received and file its  
26 revised plan with the Illinois Commerce Commission for

1 approval.

2 (2) Within 60 days after the filing of the revised  
3 plan at the Illinois Commerce Commission, any person  
4 objecting to the plan shall file an objection with the  
5 Illinois Commerce Commission. Within 30 days after the  
6 expiration of the comment period, the Illinois Commerce  
7 Commission shall determine whether an evidentiary hearing  
8 is necessary. The Illinois Commerce Commission shall also  
9 host 3 public hearings within 90 days after the plan is  
10 filed. Following the evidentiary and public hearings, the  
11 Illinois Commerce Commission shall enter its order  
12 approving or approving with modifications the reliability  
13 mitigation plan within 180 days.

14 (3) The Illinois Commerce Commission shall only  
15 approve the plan if the Illinois Commerce Commission  
16 determines that it will resolve the resource adequacy or  
17 reliability deficiency identified in the reliability  
18 mitigation plan at the least amount of CO<sub>2</sub>e and copollutant  
19 emissions, taking into consideration the emissions impacts  
20 on environmental justice communities, and that it will  
21 ensure adequate, reliable, affordable, efficient, and  
22 environmentally sustainable electric service at the lowest  
23 total cost over time, taking into account the impact of  
24 increases in emissions.

25 (4) If the resource adequacy or reliability deficiency  
26 identified in the reliability mitigation plan is resolved

1           or reduced, the Environmental Protection Agency and the  
2           Illinois Power Agency may file an amended plan adjusting  
3           the reduction or delay in CO<sub>2</sub>e and copollutant emission  
4           reduction requirements identified in the plan.

5           (Source: P.A. 104-458, eff. 6-1-26.)

6           Section 95. No acceleration or delay. Where this Act makes  
7           changes in a statute that is represented in this Act by text  
8           that is not yet or no longer in effect (for example, a Section  
9           represented by multiple versions), the use of that text does  
10          not accelerate or delay the taking effect of (i) the changes  
11          made by this Act or (ii) provisions derived from any other  
12          Public Act.