SB2295

LRB102 17361 SPS 22854 b

102ND GENERAL ASSEMBLY

State of Illinois

2021 and 2022

SB2295

Introduced 2/26/2021, by Sen. Ann Gillespie

SYNOPSIS AS INTRODUCED:

See Index

Creates the Public Utilities Intervenor Compensation Act. Provides that the Illinois Commerce Commission shall award reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs of preparation for and participation in a hearing or proceeding to a customer that complies with specified procedures and makes a contribution to the adoption of the Commission's order or decision and participation or intervention without an award of fees or costs imposes a significant financial hardship. Creates provisions concerning procedures; calculation of awards; payments and cost recovery; denial of payments; the Illinois Commerce Commission Intervenor Compensation Fund; pre-proceeding grants; and rulemaking. Amends the State Finance Act to create the Illinois Commerce Commission Intervenor Compensation Fund. Makes conforming changes in the Illinois Administrative Procedure Act and the State Finance Act. Amends the Public Utilities Act. Creates provisions concerning restitution for misconduct; the Multi-Year Integrated Grid Plan; residential time-of-use pricing; and performance-based ratemaking. Makes changes in provisions concerning the Illinois Commerce Commission; donations; natural gas surcharges; and public hearings. Makes other changes. Effective immediately.

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FISCAL NOTE ACT
MAY APPLY

A BILL FOR

AN ACT concerning regulation.

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

Section 1. Short title. This Act may be cited as the Public Utilities Intervenor Compensation Act.

Section 5. Findings. The General Assembly finds that:

(1) public participation is an important consideration in Illinois Commerce Commission proceedings;

(2) public stakeholders face financial challenges in participating at Illinois Commerce Commission proceedings, including retaining legal representation and expert witnesses;

(3) it is in the public interest to reduce barriers to participation in Illinois Commerce Commission proceedings, particularly for environmental justice and other public interest organizations;

(4) provision of compensation for participating organizations will improve Illinois Commerce Commission proceedings and decisions, increase public engagement, and encourage additional transparency.

Section 10. Definitions. As used in this Act:

"Commission" means the Illinois Commerce Commission.

"Compensation" means payment for all or part, as determined by the Commission, of reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs of preparation for and participation in a proceeding, and includes the fees and costs of obtaining an award under this Article and of obtaining judicial review, if any.

"Contribution" means that the customer's presentation has met the following standard:

(1) For any customer, the presentation has assisted the Commission in the making of its order or decision because the order or decision has adopted in whole or in part one or more factual contentions, legal contentions, or specific policy or procedural recommendations presented by the customer. For any customer, where the customer's participation has resulted in a contribution, even if the decision adopts that customer's contention or recommendations only in part, the Commission may award the customer compensation for all reasonable advocate's fees, reasonable expert fees, and other reasonable costs incurred by the customer in preparing or presenting that contention or recommendation. Participation by any customer that materially supplements, complements, or contributes to the presentation of another party, including the Commission staff, that makes a contribution to a Commission order or decision is fully eligible for compensation.

(2) For customers with fewer than 3 attorneys on staff, the customer introduces a relevant argument or factual evidence into the docket, garners a response from another party to the proceeding, and files briefs.

(3) For customers without attorneys on staff, the customer introduces a relevant argument or factual evidence into the docket.

"Customer" means any of the following:

(1) A participant representing consumers, customers, or subscribers of any electrical, gas, telephone, or water corporation that is subject to the jurisdiction of the Commission.

(2) A representative who has been authorized by a customer.

(3) A representative of a group or organization authorized pursuant to its articles of incorporation or bylaws to represent the interests of residential customers, or to represent small commercial customers who receive bundled electric service from an electrical corporation.

(4) an organization representing environmental justice communities.

"Customer" does not include any state, federal, or local governmental agency, or any publicly owned public utility. "Customer" must be a nonprofit organization.

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

"Expert witness fees" means recorded or billed costs incurred by a customer for an expert witness.

"Other reasonable costs" means reasonable out-of-pocket expenses directly incurred by a customer that are directly related to the contentions or recommendations made by the customer that resulted in a contribution.

"Party" means any interested party, respondent public utility, or Commission staff in a hearing or proceeding.

"Public utility" has the meaning ascribed to it in the Public Utilities Act.

"Significant financial hardship" means either that the customer cannot afford, without undue hardship, to pay the costs of effective participation, including advocate's fees, expert witness fees, and other reasonable costs of participation, or that, in the case of a group or organization, the economic interest of the individual members of the group or organization is small in comparison to the costs of effective participation in the proceeding.

Section 15. Intervenor compensation awards. The Commission shall award reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs of preparation for and participation in a hearing or proceeding to any customer that complies with the procedures in Section 20 and satisfies both of the following requirements:

(1) The customer's presentation makes a contribution to the adoption, in whole or in part, of the Commission's order or decision, as described in subsection (b) of Section 20; and

(2) Participation or intervention without an award of fees or costs imposes a significant financial hardship.

Section 20. Intervenor compensation award procedures.

(a)(1) A customer that intends to seek an award under this Article shall, within 30 days after the prehearing conference is held, file and serve on all parties to the proceeding a notice of intent to claim compensation. The Commission shall determine the procedure to be used in cases in which:

(i) no prehearing conference is scheduled;

(ii) the Commission anticipates that the proceeding will take less than 30 days;

(iii) the schedule would not reasonably allow parties to identify issues within the time frame set forth in this subsection; or

(iv) where new issues emerge after the time set for filing.

(2)(i) The notice of intent to claim compensation shall include both of the following:

(A) A statement of the nature and extent of the customer's planned participation in the proceeding as far as it is possible to set it out when the notice of intent is filed.

(B) An itemized estimate of the compensation that the customer expects to request, given the likely duration of the proceeding as it appears at the time.

(ii) The notice of intent may also include a showing by the customer that participation in the hearing or proceeding would pose a significant financial hardship. Alternatively, such a showing shall be included in the request submitted pursuant to subsection (c).

(3) Within 15 days after service of the notice of intent to claim compensation, the administrative law judge may direct the staff, and may permit any other interested party, to file a statement responding to the notice.

(b)(1) If the customer's showing of significant financial hardship was included in the notice filed pursuant to subsection (a), the administrative law judge shall issue within 30 days thereafter a preliminary ruling addressing whether the customer is eligible for an award of compensation. The ruling shall address whether a showing of significant financial hardship has been made. A finding of significant financial hardship shall create a rebuttable presumption of eligibility for compensation in other Commission proceedings commencing within 2 years after the date of that finding.

(2) The administrative law judge may, in any event, issue

a ruling addressing issues raised by the notice of intent to claim compensation. The ruling may point out similar positions, areas of potential duplication in showings, unrealistic expectation for compensation, and any other matter that may affect the customer's ultimate claim for compensation. Failure of the ruling to point out similar positions or potential duplication or any other potential impact on the ultimate claim for compensation shall not imply approval of any claim for compensation. A finding of significant financial hardship in no way ensures compensation. Similarly, the failure of the customer to identify a specific issue in the notice of intent or to precisely estimate potential compensation shall not preclude an award of reasonable compensation if a contribution is made.

(c) Following issuance of a final order or decision by the Commission in the hearing or proceeding, a customer that has been found, pursuant to subsection (b), to be eligible for an award of compensation may file within 60 days a request for an award. The request shall include at a minimum a detailed description of services and expenditures and a description of the customer's contribution to the hearing or proceeding. Within 30 days after service of the request, the Commission staff may file, and any other party may file, a response to the request.

(d) The Commission may audit the records and books of the customer to the extent necessary to verify the basis for the award. The Commission shall preserve the confidentiality of the customer's records in making its audit. Within 20 days after completion of the audit, if any, the Commission shall direct that an audit report shall be prepared and filed. Any other party may file a response to the audit report within 20 days thereafter.

(e) Within 75 days after the filing of a request for compensation pursuant to subsection (c), or within 50 days after the filing of an audit report, whichever occurs later, the Commission shall issue a decision that determines whether or not the customer has made a contribution to the final order or decision in the hearing or proceeding. If the Commission finds that the customer requesting compensation has made a contribution, the Commission shall describe this contribution and shall determine the amount of compensation to be paid.

Section 25. Calculation of intervenor compensation awards. The computation of compensation awarded shall take into consideration the market rates paid to persons of comparable training and experience who offer similar services. The compensation awarded may not exceed the comparable market rate for services paid by the Commission or the public utility, whichever is greater, to persons of comparable training and experience who are offering similar services.

Section 30. Intervenor compensation payments and cost recovery. An award made under this Act shall be paid by the public utility that is the subject of the hearing, investigation, or proceeding, as determined by the Commission, within 30 days. Notwithstanding any other law, an award paid by a public utility pursuant to this Act shall be allowed by the Commission as an expense for the purpose of establishing rates of the public utility.

Section 35. Denial of intervenor compensation payments. The Commission shall deny any award to any customer that attempts to delay or obstruct the orderly and timely fulfillment of the Commission's responsibilities.

Section 40. Illinois Commerce Commission Intervenor Compensation Fund. The Illinois Commerce Commission Intervenor Compensation Fund is hereby created as a special fund in the State treasury. The Commission shall administer the Illinois Commerce Commission Intervenor Compensation Fund for use as described in Section 45. An electric public utility with 3,000,000 or more retail customers shall contribute $450,000 to the Illinois Commerce Commission Intervenor Compensation Fund within 60 days after the effective date of this Act. A combined electric and gas public utility serving fewer than 3,000,000 but more than 500,000 retail customers shall contribute $225,000 to the Illinois Commerce Commission Intervenor Compensation Fund within 60 days after the effective date of this Act. A gas public utility with 2,000,000 or more retail customers that is not a combined electric and gas public utility shall contribute $225,000 to the Illinois Commerce Commission Intervenor Compensation Fund within 60 days after the effective date of this Act. A gas public utility with fewer than 2,000,000 retail customers but more than 300,000 retail customers that is not a combined electric and gas public utility shall contribute $80,000 to the Illinois Commerce Commission Intervenor Compensation Fund within 60 days after the effective date of this Act. A gas public utility with fewer than 300,000 retail customers that is not a combined electric and gas public utility shall contribute $20,000 to the Illinois Commerce Commission Intervenor Compensation Fund within 60 days after the effective date of this Act.

Section 45. Intervenor compensation pre-proceeding grants.

(a) Any customer that applies for intervenor compensation payments under subsection (a) of Section 20 may also, at the same time, apply for a grant from the Illinois Commerce Commission Intervenor Compensation Fund for the costs described in its notice of intent to claim compensation. A final decision regarding the grant shall be made at the time of the preliminary ruling on intervenor compensation eligibility in subsection (b) of Section 20. No pre-proceeding grant shall be given to organizations who are not found to be eligible for intervenor compensation. If granted, payments must be made within 30 days to facilitate participation in the proceeding. At the time of the final decision regarding the grant, the Commission shall notify the customer of the requirements to be awarded intervenor compensation and that, if the customer does not prevail in receiving intervenor compensation of at least the amount of the grant, the customer will be expected to reimburse the Illinois Commerce Commission Intervenor Compensation Fund for the remaining grant moneys on a regular schedule within 5 years of the end of the proceeding. After notification, the customer may accept or deny receipt of the grant.

(b) To apply for a grant from the Illinois Commerce Commission Intervenor Compensation Fund, the customer must describe why prepayment of intervenor compensation is necessary for it to participate in the proceeding and show financial hardship sufficient that the customer cannot reasonably be expected to participate without receiving a grant.

(c) If a customer that receives a grant from the Illinois Commerce Commission Intervenor Compensation Fund subsequently prevails in receiving intervenor compensation, the public utility paying intervenor compensation must reimburse the fund for the amount of the grant. If the intervenor compensation amount is larger than the grant, then the balance shall be paid to the customer. If the amount of intervenor compensation is less than the grant, then the customer must reimburse the Illinois Commerce Commission Intervenor Compensation Fund for the difference with payments made on a regular schedule within 5 years after the end of the proceeding.

(d) If a customer that receives a grant from the Illinois Commerce Commission Intervenor Compensation Fund does not subsequently prevail in receiving intervenor compensation, then the customer must reimburse the Illinois Commerce Commission Intervenor Compensation Fund for the amount of the grant with payments made on a regular schedule within 5 years of the end of the proceeding.

Section 50. Rulemaking. The Commission shall adopt any rules necessary to implement this Act. The Commission has the authority to initiate an emergency rulemaking to adopt rules regarding intervenor compensation if necessary to allow customer participation in dockets implementing new statutes.

Section 80. The Illinois Administrative Procedure Act is amended by adding Section 5-45.8 as follows:

(5 ILCS 100/5-45.8 new)

Sec. 5-45.8. Emergency rulemaking; Public Utilities Intervenor Compensation Act. To provide for the expeditious and timely implementation of the Public Utilities Intervenor Compensation Act, emergency rules may be adopted in accordance with Section 5-45 by the Illinois Commerce Commission to implement the Public Utilities Intervenor Compensation Act. The adoption of emergency rules authorized by Section 5-45 and this Section is deemed to be necessary for the public interest, safety, and welfare.

This Section is repealed on January 1, 2027.

Section 85. The State Finance Act is amended by adding Section 5.935 as follows:

(30 ILCS 105/5.935 new)

Sec. 5.935. The Illinois Commerce Commission Intervenor Compensation Fund.

Section 90. The Public Utilities Act is amended by changing Sections 2-107, 9-220.3, 9-227, and 10-104 and by adding Sections 4-605, 16-105.17, 16-107.7, and 16-108.18 as follows:

(220 ILCS 5/2-107) (from Ch. 111 2/3, par. 2-107)

Sec. 2-107. The office of the Commission shall be in Springfield, but the Commission may, with the approval of the Governor, establish and maintain branch offices at places other than the seat of government. Such office shall be open for business between the hours of 8:30 a.m. and 5:00 p.m. throughout the year, and one or more responsible persons to be designated by the executive director shall be on duty at all times in immediate charge thereof.

The Commission shall hold stated meetings at least once a month and may hold such special meetings as it may deem necessary at any place within the State. At each regular and special meeting that is open to the public, members of the public shall be afforded time, subject to reasonable constraints, to make comments to or to ask questions of the Commission. In any contested or rulemaking proceeding, at the request of any party or at least 5 members of the public, the Commission shall hold at least one public hearing, at a time and place accessible and convenient for affected customers to participate, where members of the public are invited to participate and present public comments in accordance with 2 Ill. Adm. Code 1700.10. The hearing must take place at least 30 days prior to the Commission's final order on the case.

The Commission shall provide a web site and a toll-free telephone number to accept comments from Illinois residents regarding any matter under the auspices of the Commission or before the Commission. The Commission staff shall report, in a manner established by the Commission that is consistent with the Commission's rules regarding ex parte communications, to the full Commission comments and suggestions received through both venues before all relevant votes of the Commission.

The Commission may, for the authentication of its records, process and proceedings, adopt, keep and use a common seal, of which seal judicial notice shall be taken in all courts of this State; and any process, notice, order or other paper which the Commission may be authorized by law to issue shall be deemed sufficient if signed and certified by the Chairman of the Commission or his or her designee, either by hand or by facsimile, and with such seal attached; and all acts, orders, proceedings, rules, entries, minutes, schedules and records of the Commission, and all reports and documents filed with the Commission, may be proved in any court of this State by a copy thereof, certified to by the Chairman of the Commission, with the seal of the Commission attached.

Notwithstanding any other provision of this Section, the Commission's established procedures for accepting testimony from Illinois residents on matters pending before the Commission shall be consistent with the Commission's rules regarding ex parte communications and due process.

(Source: P.A. 95-127, eff. 8-13-07.)

(220 ILCS 5/4-605 new)

<u>Sec. 4-605. Restitution for misconduct.</u>

<u>(a) It is the policy of this State that public utility ethical and criminal misconduct shall not be tolerated. The General Assembly finds it necessary to collect restitution, to be distributed as described in subsection (d), from a public utility who has been found guilty of violations of criminal law or who has entered into a Deferred Prosecution Agreement</u>

that details violations of criminal law.

(b) In light of such violations, the Illinois Commerce Commission shall, within 150 days after the effective date of this amendatory Act of the 102nd General Assembly, initiate an investigation into amounts necessary to be refunded to customers to restore funds to the State and to ratepayers that were collected by the electric public utility Commonwealth Edison Company as a result of ethical misconduct. The investigation shall conclude no later than 270 days following initiation, and shall be conducted as a contested proceeding. The investigation shall calculate benefits received by the public utility that were instituted as a result of illegal and unethical conduct, as set forth in the Deferred Prosecution Agreement of July 16, 2020 between the United States Attorney for the Northern District of Illinois and Commonwealth Edison Company, for passage of the Energy Infrastructure Modernization Act of 2011. The amount shall be no less than the total return on equity recovered for investments in infrastructure made pursuant to paragraph (1) of subsection (b) of Section 16-108.5 of this Act.

(c) Pursuant to subsection (d), the investigation shall calculate a schedule for remittance to state funds and to ratepayers, over a period of no more than 4 years, to be paid by the public utility from profits, returns, or shareholder dollars. No costs related to the investigation, restitution, or refunds may be recoverable through rates.

(d) Funds collected pursuant to this Section shall be repaid by the public utility in the following manner:

(1) 25% shall be contributed to expand the Percentage of Income Payment Program;

(2) the remaining percentage of funds collected shall be provided as a per-kilowatt-hour credit to the public utility's ratepayers.

(220 ILCS 5/9-220.3)

(Section scheduled to be repealed on December 31, 2023)

Sec. 9-220.3. Natural gas surcharges authorized.

(a) Tariff.

(1) Pursuant to Section 9-201 of this Act, a natural gas utility serving more than 700,000 customers may file a tariff for a surcharge which adjusts rates and charges to provide for recovery of costs associated with investments in qualifying infrastructure plant, independent of any other matters related to the utility's revenue requirement.

(2) Within 30 days after the effective date of this amendatory Act of the 98th General Assembly, the Commission shall adopt emergency rules to implement the provisions of this amendatory Act of the 98th General Assembly. The utility may file with the Commission tariffs implementing the provisions of this amendatory Act of the 98th General Assembly after the effective date of the

emergency rules authorized by subsection (i).

(3) The Commission shall issue an order approving, or approving with modification to ensure compliance with this Section, the tariff no later than 120 days after such filing of the tariffs filed pursuant to this Section. The utility shall have 7 days following the date of service of the order to notify the Commission in writing whether it will accept any modifications so identified in the order or whether it has elected not to proceed with the tariff. If the order includes no modifications or if the utility notifies the Commission that it will accept such modifications, the tariff shall take effect on the first day of the calendar year in which the Commission issues the order, subject to petitions for rehearing and appellate procedures. After the tariff takes effect, the utility may, upon 10 days' notice to the Commission, file to withdraw the tariff at any time, and the Commission shall approve such filing without suspension or hearing, subject to a final reconciliation as provided in subsection (e) of this Section.

(4) When a natural gas utility withdraws the surcharge tariff, the utility shall not recover any additional charges through the surcharge approved pursuant to this Section, subject to the resolution of the final reconciliation pursuant to subsection (e) of this Section. The utility's qualifying infrastructure investment net of

accumulated depreciation may be transferred to the natural gas utility's rate base in the utility's next general rate case. The utility's delivery base rates in effect upon withdrawal of the surcharge tariff shall not be adjusted at the time the surcharge tariff is withdrawn.

(5) A natural gas utility that is subject to its delivery base rates being fixed at their current rates pursuant to a Commission order entered in Docket No. 11-0046, notwithstanding the effective date of its tariff authorized pursuant to this Section, shall reflect in a tariff surcharge only those projects placed in service after the fixed rate period of the merger agreement has expired by its terms.

(b) For purposes of this Section, "qualifying infrastructure plant" includes only plant additions placed in service not reflected in the rate base used to establish the utility's delivery base rates. "Costs associated with investments in qualifying infrastructure plant" shall include a return on qualifying infrastructure plant and recovery of depreciation and amortization expense on qualifying infrastructure plant, net of the depreciation included in the utility's base rates on any plant retired in conjunction with the installation of the qualifying infrastructure plant. Collectively the "qualifying infrastructure plant" and "costs associated with investments in qualifying infrastructure plant" are referred to as the "qualifying infrastructure investment" and that are related to one or more of the following:

(1) the installation of facilities to retire and replace underground natural gas facilities, including facilities appurtenant to facilities constructed of those materials such as meters, regulators, and services, and that are constructed of cast iron, wrought iron, ductile iron, unprotected coated steel, unprotected bare steel, mechanically coupled steel, copper, Cellulose Acetate Butyrate (CAB) plastic, pre-1973 DuPont Aldyl "A" polyethylene, PVC, or other types of materials identified by a State or federal governmental agency as being prone to leakage;

(2) the relocation of meters from inside customers' facilities to outside;

(3) the upgrading of the gas distribution system from a low pressure to a medium pressure system, including installation of high-pressure facilities to support the upgrade;

(4) modernization investments by a combination utility, as defined in subsection (b) of Section 16-108.5 of this Act, to install:

(A) advanced gas meters in connection with the installation of advanced electric meters pursuant to Sections 16-108.5 and 16-108.6 of this Act; and

(B) the communications hardware and software and associated system software that creates a network between advanced gas meters and utility business systems and allows the collection and distribution of gas-related information to customers and other parties in addition to providing information to the utility itself;

(5) replacing high-pressure transmission pipelines and associated facilities identified as having a higher risk of leakage or failure or installing or replacing high-pressure transmission pipelines and associated facilities to establish records and maximum allowable operating pressures;

(6) replacing difficult to locate mains and service pipes and associated facilities; and

(7) replacing or installing transmission and distribution regulator stations, regulators, valves, and associated facilities to establish over-pressure protection.

With respect to the installation of the facilities identified in paragraph (1) of subsection (b) of this Section, the natural gas utility shall determine priorities for such installation with consideration of projects either: (i) integral to a general government public facilities improvement program or (ii) ranked in the highest risk categories in the utility's most recent Distribution Integrity Management Plan where removal or replacement is the remedial measure.

(c) Qualifying infrastructure investment, defined in subsection (b) of this Section, recoverable through a tariff authorized by subsection (a) of this Section, shall not include costs or expenses incurred in the ordinary course of business for the ongoing or routine operations of the utility, including, but not limited to:

(1) operating and maintenance costs; and

(2) costs of facilities that are revenue-producing, which means facilities that are constructed or installed for the purpose of serving new customers.

(d) Gas utility commitments. A natural gas utility that has in effect a natural gas surcharge tariff pursuant to this Section shall:

(1) recognize that the General Assembly identifies improved public safety and reliability of natural gas facilities as the cornerstone upon which this Section is designed, and qualifying projects should be encouraged, selected, and prioritized based on these factors; and

(2) provide information to the Commission as requested to demonstrate that (i) the projects included in the tariff are indeed qualifying projects and (ii) the projects are selected and prioritized taking into account improved public safety and reliability.

(3) The amount of qualifying infrastructure investment eligible for recovery under the tariff in the applicable calendar year is limited to the lesser of (i) the actual

qualifying infrastructure plant placed in service in the applicable calendar year and (ii) the difference by which total plant additions in the applicable calendar year exceed the baseline amount, and subject to the limitation in subsection (g) of this Section. A natural gas utility can recover the costs of qualifying infrastructure investments through an approved surcharge tariff from the beginning of each calendar year subject to the reconciliation initiated under paragraph (2) of subsection (e) of this Section, during which the Commission may make adjustments to ensure that the limits defined in this paragraph are not exceeded. Further, if total plant additions in a calendar year do not exceed the baseline amount in the applicable calendar year, the Commission, during the reconciliation initiated under paragraph (2) of subsection (e) of this Section for the applicable calendar year, shall adjust the amount of qualifying infrastructure investment eligible for recovery under the tariff to zero.

(4) For purposes of this Section, "baseline amount" means an amount equal to the utility's average of total depreciation expense, as reported on page 336, column (b) of the utility's ILCC Form 21, for the calendar years 2006 through 2010.

(e) Review of investment.

(1) The amount of qualifying infrastructure investment shall be shown on an Information Sheet supplemental to the

surcharge tariff and filed with the Commission monthly or some other time period at the option of the utility. The Information Sheet shall be accompanied by data showing the calculation of the qualifying infrastructure investment adjustment. Unless otherwise ordered by the Commission, each qualifying infrastructure investment adjustment shown on an Information Sheet shall become effective pursuant to the utility's approved tariffs.

(2) For each calendar year in which a surcharge tariff is in effect, the natural gas utility shall file a petition with the Commission to initiate hearings to reconcile amounts billed under each surcharge authorized pursuant to this Section with the actual prudently incurred costs recoverable under this tariff in the preceding year. The petition filed by the natural gas utility shall include testimony and schedules that support the accuracy and the prudence of the qualifying infrastructure investment for the calendar year being reconciled. The petition filed shall also include the number of jobs attributable to the natural gas surcharge tariff as required by rule. The review of the utility's investment shall include identification and review of all plant that was ranked within the highest risk categories in that utility's most recent Distribution Integrity Management Plan.

(f) The rate of return applied shall be the overall rate of return authorized by the Commission in the utility's last gas rate case.

(g) The cumulative amount of increases billed under the surcharge, since the utility's most recent delivery service rate order, shall not exceed an annual average 4% of the utility's delivery base rate revenues, but shall not exceed 5.5% in any given year. On the effective date of new delivery base rates, the surcharge shall be reduced to zero with respect to qualifying infrastructure investment that is transferred to the rate base used to establish the utility's delivery base rates, provided that the utility may continue to charge or refund any reconciliation adjustment determined pursuant to subsection (e) of this Section.

(h) If a gas utility obtains a surcharge tariff under this Section 9-220.3, then it and its affiliates are excused from the rate case filing requirements contained in Sections 9-220(h) and 9-220(h-1). In the event a natural gas utility, prior to the effective date of this amendatory Act of the 98th General Assembly, made a rate case filing that is still pending on the effective date of this amendatory Act of the 98th General Assembly, the natural gas utility may, at the time it files its surcharge tariff with the Commission, also file a notice with the Commission to withdraw its rate case filing. Any affiliate of such natural gas utility may also file to withdraw its rate case filing. Upon receipt of such notice, the Commission shall dismiss the rate case filing with prejudice and such tariffs and the record related thereto shall not be the subject of any further hearing, investigation, or proceeding of any kind related to rates for gas delivery services. Notwithstanding the foregoing, a natural gas utility shall not be permitted to withdraw a rate case filing for which a proposed order recommending a rate reduction is pending. A natural gas utility shall not be permitted to withdraw the gas delivery services tariffs that are the subject of Commission Docket Nos. 12-0511/12-0512 (cons.). None of the costs incurred for the withdrawn rate case are recoverable from ratepayers.

(i) The Commission shall promulgate rules and regulations to carry out the provisions of this Section under the emergency rulemaking provisions set forth in Section 5-45 of the Illinois Administrative Procedure Act, and such emergency rules shall be effective no later than 30 days after the effective date of this amendatory Act of the 98th General Assembly.

<u>(j) Utilities that have elected to recover qualifying infrastructure investment costs pursuant to this Section shall file annually their Distribution Integrity Management Plan (DIMP) with the Commission no later than June 1 of each year the utility has said tariff in effect. The DIMP shall include the following information:</u>

<u>(1) Baseline Distribution System Data: Information such as demand, system pressures and flows, and metering</u>

infrastructure.

(2) Financial Data: historical and projected spending on distribution system infrastructure.

(3) Scenario Analysis: Discussion of projected changes in usage over time.

(4) Descriptions of all qualifying infrastructure investment proposed for the coming year.

(k) Within 45 days after filing, the Commission shall, with reasonable notice, open an investigation to consider whether the Plan meets the objectives set forth in this subsection and contains the information required by subsection (j). The Commission shall issue a final order approving the Plan, with any modifications the Commission deems reasonable and appropriate to achieve the goals of this Section, within 270 days after the Plan filing. The investigation shall assess whether the DIMP:

(1) ensures optimized use of utility infrastructure assets and resources to minimize total system costs;

(2) enables greater customer engagement, empowerment, and options for services;

(3) to the maximum extent possible, achieves and or supports the achievement of greenhouse gas emissions reductions as described by Section 9.10 of the Environmental Protection Act; and

(4) supports existing Illinois policy goals promoting energy efficiency.

The Commission process shall maximize the sharing of information, ensure robust stakeholder participation, and recognize the responsibility of the utility to ultimately manage the grid in a safe, reliable manner.

(l) ~~(j)~~ This Section is repealed December 31, 2023.

(Source: P.A. 98-57, eff. 7-5-13.)

(220 ILCS 5/9-227) (from Ch. 111 2/3, par. 9-227)

Sec. 9-227. It is the policy of this State to encourage electric and natural gas public utilities to promote the welfare of this State and their communities through donations made from the utility's shareholder profits rather than by using ratepayer funds. Such contributions shall not be recoverable through the public utility's rates. ~~It shall be proper for the Commission to consider as an operating expense, for the purpose of determining whether a rate or other charge or classification is sufficient, donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount. In determining the reasonableness of such donations, the Commission may not establish, by rule, a presumption that any particular portion of an otherwise reasonable amount may not be considered as an operating expense. The Commission shall be prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes.~~

(Source: P.A. 85-122.)

(220 ILCS 5/10-104) (from Ch. 111 2/3, par. 10-104)

Sec. 10-104. Public hearings.

(a) As used in this Section, "major case" includes:

(1) rate cases;

(2) rulemakings;

(3) other proceedings with a significant effect on rates;

(4) large infrastructure projects with significant nonrate impacts on communities near their location;

(5) new programs;

(6) any planning dockets related to energy efficiency, renewable energy, and interconnection infrastructure; and

(7) any other docketed or undocketed proceedings for which the Commission feels that robust public engagement is needed.

(b) When the outcome of a major case would have effects statewide, or have any significant effects outside the territory of the utility or utilities involved in the case, the Commission shall hold at least 5 public hearings for the purpose of receiving public comment on each such major case. One of these hearings must be in the Chicago metropolitan area. One of these hearings must be in Springfield. The remaining 3 hearings must be outside of the Chicago metropolitan area and Springfield. One of the hearings shall be held within the county in which the subject matter of the hearing is situated, if it is situated within one county. When the outcome of a major case would have effects only within the territory of one utility, the Commission shall hold at least 5 public hearings at a variety of geographic locations within the utility's territory. The locations shall be chosen to give a wide variety of stakeholders the best opportunity to participate in the hearings. The Commission may combine public hearings for multiple major cases into one event at a single venue, where practicable and compliant with all other requirements.

(c) The public hearings shall be held at times that make them accessible to the public, including to residents who work during the day. The public hearings shall be held at locations easily accessible, whenever possible, by public transportation. The public hearings shall be held at locations with wheelchair access. Upon request, a sign language interpreter or other equivalent assistance for the hearing impaired shall be provided. Upon request, translation services shall be provided. Translation services may include real-time telephone-based or other real-time translation services. All written materials distributed at public hearings by the Commission or utilities must be available at the hearing in Spanish and, upon request and reasonable notice, other languages. Call-in options shall be provided.

(d) At least 3 commissioners shall attend each public hearing in person.

(e) Public hearings under this Section are subject to the Open Meetings Act.

(f) The Commission may collect a reasonable fee from the affected utility to offset the cost of public hearings, including the cost of staffing. Within 30 days after the effective date of this amendatory Act of the 102nd General Assembly, the Commission shall set the amount of the fee and shall update the amount of the fee no less often than every 3 years thereafter. All fees charged and collected by the Commission shall be paid promptly after the receipt of the same, accompanied by a detailed statement thereof, into the Public Utility Fund in the State treasury. ~~All hearings before the Commission or any commissioner or administrative law judge shall be held within the county in which the subject matter of the hearing is situated, or if the subject matter of the hearing is situated in more than one county, then at a place or places designated by the Commission, or agreed upon by the parties in interest, within one or more such counties, or at the place which in the judgment of the Commission shall be most convenient to the parties to be heard.~~

(Source: P.A. 100-840, eff. 8-13-18.)

(220 ILCS 5/16-105.17 new)

Sec. 16-105.17. Multi-Year Integrated Grid Plan.

(a) Findings and Purpose. The General Assembly finds that better aligning regulated utility operations, expenditures and investments with public benefit goals including safety; reliability; efficiency; affordability; equity; emissions reductions; and expansion of clean distributed energy resources, is critical to ensuring that Illinois residents and businesses do not suffer economic and environmental harm from the State's energy systems and to maximize the potential benefits from utility expenditures. To that end, it is the policy of the State of Illinois to promote inclusive, comprehensive, transparent, cost-effective distribution system planning that minimizes long-term costs for Illinois customers and supports the achievement of state renewable energy development and other clean energy, public health, and environmental policy goals. Utility distribution system expenditures, programs, investments and policies must be evaluated in coordination with these goals. In particular, the General Assembly finds that:

(1) Illinois' electricity distribution system must cost-effectively integrate renewable energy resources, including utility-scale renewable energy resources, community renewable generation and distributed renewable energy resources, support beneficial electrification including electric vehicle use and adoption, promote opportunities for third-party investment in nontraditional, grid-related technologies and resources such as batteries, solar photovoltaic panels and smart

thermostats, reduce energy usage generally and especially during times of greatest reliance on fossil fuels, and enhance customer engagement opportunities.

(2) Inclusive distribution system planning is an essential tool for the Illinois Commerce Commission, public utilities, and stakeholders to effectively coordinate environmental, consumer, reliability and equity goals at fair and reasonable costs, and for ensuring transparent utility accountability for meeting those goals.

(3) Any planning process should advance Illinois energy policy goals while ensuring utility investments are cost-effective. Such a process should maximize the sharing of information, ensure robust stakeholder participation, and recognize the responsibility of the utility to ultimately manage the grid in a safe, reliable manner.

(4) Since the passage of the Energy Infrastructure Modernization Act in 2011, Illinois consumers have invested billions of dollars toward electric utility grid modernization. In the absence of a transparent distribution planning process, however, those investments have not served customers' best interests, have failed to promote the expansion of clean distributed energy resources, and have failed to advance equity and environmental justice.

(5) The traditional regulatory model rewards utilities

for increasing capital expenditures by basing allowed revenues on the value of the rate base, resulting in an incentive for ever-increasing capital investments. The General Assembly is concerned that the existing regulatory model does not align the interests of customers, the State, and utilities because it does not encourage utilities to systematically analyze and consider nontraditional solutions to utility, customer and grid needs that may be more efficient and cost effective, and less environmentally harmful than traditional solutions. Nontraditional solutions include distributed energy resources owned or implemented by customers and independent third parties, controllable load, beneficial electrification, or rate design that rewards efficient energy use, for example.

(6) The General Assembly also finds that Illinois utilities' current processes for planning their distribution system are not reasonably accessible or transparent to individuals and communities who pay for and are affected by the utilities' distribution system assets, and that more inclusive and accessible distribution system planning processes would be in the interests of all Illinois residents, but especially those residents historically most negatively impacted by unsafe or environmentally harmful energy infrastructure.

(7) The General Assembly finds it would be beneficial

to require utilities to demonstrate how their spending promotes identified state energy goals, such as integrating renewable energy; empowering customers; supporting electric vehicles, beneficial electrification and energy storage; achieving equity goals; and maintaining reliability.

The General Assembly therefore directs the utilities to implement distribution system planning in order to accelerate progress on Illinois clean energy and environmental goals and hold electric utilities publicly accountable for their performance.

(b) Definitions. As used in this Section:

"Commission" means the Illinois Commerce Commission.

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

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

"Environmental justice communities" means the definition of that term based on existing methodologies and findings, used and as may be updated by the Illinois Power Agency and its Program Administrator in the Illinois Solar for All Program.

(c) Application. This Section applies to electric utilities serving more than 500,000 retail customers in the State.

(d) Objectives. The Multi-Year Integrated Grid Plan ("the Plan") shall be designed to:

(1) ensure coordination of the State's renewable energy goals, climate and environmental goals, utility distribution system investments, and programs, policies and investments described in this Section to maximize the benefits of each while ensuring utility expenditures are cost-effective;

(2) bring the benefits of grid modernization and clean energy, including, but not limited to, deployment of distributed energy resources, to ratepayers in economically disadvantaged and environmental justice communities throughout Illinois, with at least 40% of these benefits being allocated to these ratepayers;

(3) enable greater customer engagement, empowerment, and options for energy services;

(4) reduce grid congestion, minimize the time and expense associated with interconnection, and increase the capacity of the distribution grid to host increasing levels of distributed energy resources, to facilitate availability and development of distributed energy resources, particularly in locations that enhance consumer and environmental benefits;

(5) ensure opportunities for robust public participation through open, transparent planning processes;

(6) provide for the analysis of the cost-effectiveness of proposed system investments, which takes into account environmental costs and benefits;

(7) to the maximum extent possible, achieve or support the achievement of Illinois environmental goals, including those described in Section 9.10 of the Environmental Protection Act, Section 1-75 of the Illinois Power Agency Act, and emissions reductions required to improve the health, safety and prosperity of all Illinois residents;

(8) support existing Illinois policy goals promoting distributed energy resources and investments in renewable energy resources; and

(9) provide sufficient public information to the Commission, stakeholders, and market participants in order to enable nonemitting customer-owned or third-party distributed energy resources, acting individually or in aggregate, to seamlessly and easily connect to the grid; provide grid benefits; support grid services; and achieve environmental outcomes, without necessarily requiring utility ownership or unreasonable control over those resources, and enable those resources to act as alternatives to utility capital investments.

(e) Plan Development Stakeholder Process. No later than

February 1, 2022, the Illinois Commerce Commission shall initiate a series of no fewer than 6 workshops which shall inform the filing requirements for, and contents of, the Multi-Year Integrated Grid Plans to be filed by electric utilities subject to this Section. The series of workshops shall be 11 months in length, concluding no later than December 31, 2022. The workshops shall be facilitated by an independent third-party facilitator selected by Staff of the Illinois Commerce Commission and approved by the Executive Director of the Illinois Commerce Commission.

(1) The workshops shall be designed to achieve the following objectives:

(i) review utilities' past, current and planned capital investments and all supporting data;

(ii) review utilities' historic and projected load;

(iii) review how utilities plan to invest in their distribution system in order to meet the system's projected needs;

(iv) review locational data on reliability, service quality, program participation and investment, provided by the utilities;

(v) integrate input from diverse stakeholders, including representatives from environmental justice communities, geographically diverse communities, low-income representatives, consumer representatives, environmental representatives, organized labor representatives, third-party technology providers, and utilities;

(vi) consider proposals from utilities and stakeholders on programs and policies necessary to achieve the objectives in subsection (d) of this Section; and

(vii) develop detailed filing requirements applicable to each component of the utilities' Multi-Year Integrated Grid Plan filings under paragraph (2) of subsection (f) of this Section.

(2) To the extent any of the information in subparagraphs (i) through (iv) of paragraph (1) of this subsection is designated as confidential because disclosure of such threatens the security of critical system infrastructure, that information shall be redacted as necessary but made available to parties who agree in writing to abide by confidentiality agreements as approved by the Office of General Counsel of the Illinois Commerce Commission. Information appropriately designated as confidential shall only include that which is critical to system security, and shall not include that information in which the electric utility claims a proprietary business interest.

(3) Workshops should be organized and facilitated in a manner that encourages representation from diverse

stakeholders, ensuring equitable opportunities for participation, without requiring formal intervention or representation by an attorney. Workshops should be held during both day and evening hours, in a variety of locations around the State, and should allow remote participation.

(4) Utilities shall provide system data, including data described in subparagraphs (i) through (iv) of paragraph (1) of subsection (e), at a time prior to the start of workshops to allow interested stakeholders to reasonably review data before attending workshops. To facilitate public feedback, the administrator facilitating the workshops shall, throughout the workshop process, develop questions for stakeholder input on topics being considered. This may include, but is not limited to: design of the workshop process, locational data and information provided by utilities, alignment of plans, programs, investments and objectives, and other topics as deemed appropriate by the Commission facilitation staff. Stakeholder feedback shall not be limited to these questions.

(5) Workshops shall not be considered settlement negotiations, compromise negotiations, or offers to compromise for the purposes of Illinois Rule of Evidence 408. All materials shared as a part of the workshop process shall be made publicly available on a website made

available by the Commission.

(6) On conclusion of the workshops, the Commission shall open a comment period that allows interested and diverse stakeholders to submit comments and recommendations regarding the utilities' Multi-Year Integrated Grid Plan filings. Based on the workshop process and stakeholder comments and recommendations offered verbally or in writing during the workshops and in writing during the comment period following the workshops, the independent third-party facilitator shall prepare a report, to be submitted to the Commission no later than February 1, 2022, describing the stakeholders, discussions, proposals, and areas of consensus and disagreement from the workshop process, and making recommendations to the Commission regarding the utilities' Multi-Year Integrated Grid Plan filings. Interested stakeholders shall have an opportunity to provide comment on the independent third-party facilitator Report.

(7) Based on discussions in the workshops, the Staff Report, and stakeholder comments and recommendations made during and following the workshop process, the Commission shall issue Initiating Orders no later than April 1, 2022, requiring the electric utilities subject to this Section to file the first Multi-Year Integrated Grid Plan no later than June 1, 2022. The Initiating Orders shall specify the requirements applicable to the utilities' Multi-Year

Integrated Grid Plans, above and beyond any requirements described in paragraph (2) of subsection (f) of this Section, and shall:

(i) analyze and identify specific programs, policies, and initiatives, among those that were raised during the workshop process, that the utilities must implement as a part of their Multi-Year Integrated Grid Plans; and

(ii) specify types of analyses and calculations the utilities shall perform, as well as scenarios they must analyze and (where applicable) specific assumptions they must use in the development of their Multi-Year Integrated Grid Plans.

(f) Multi-Year Integrated Grid Plan.

(1) Design Objectives. Pursuant to this subsection (f) of this Section 1and the Initiating Orders of the Commission, to be filed no later than April 1, 2022, and for each subsequent Plan thereafter, each electric utility subject to this Section shall, no later than June 1, 2022, submit its first Multi-Year Integrated Grid Plan. While each Multi-Year Integrated Grid Plan will include a long-term, ten-year planning horizon, the Initial Plan shall be in effect from June 1, 2023 through May 31, 2026. Each Plan shall:

(i) incorporate requirements established by the Commission in its Initiating Order; and

(ii) Propose programs, policies and plans designed to optimize achievement of the objectives set forth in subsection (d) of this Section.

To the extent practicable and reasonable, all programs, policies and initiatives proposed by the utility in its plan should be informed by stakeholder input received during the workshop process pursuant to subsection (e) of this Section. Where specific stakeholder input has not been incorporated in proposed programs, policies, and plans, the electric utility shall provide an explanation as to why that input was not incorporated.

(2) Plan Components. In order to ensure electric utilities' ability to meet the goals and objectives set forth in this Section, the Multi-Year Integrated Grid Plans must include, at minimum, the following information:

(i) Baseline Distribution System Data. A detailed description of the current operating conditions for the distribution system, including a detailed description, with supporting data, of: system conditions, including asset age and useful life, ratings, loadings, and other characteristics, as well as:

(A) modeling software currently used and planned software deployments;

(B) the distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages);

(C) the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system;

(D) total distribution substation capacity in kVa;

(E) total distribution transformer capacity in kVa;

(F) total miles of overhead distribution wire;

(G) total miles of underground distribution wire;

(H) current and expected reliability measures;

(I) detailed listing of all high-voltage and low-voltage substations and circuits including, at minimum, the following for each substation and circuit: age, remaining useful life, capacity rating, historical peak demand, historical interval data, historic annual peak load growth, forecast future annual peak load growth, historical outages and voltage violations, distribution system reliability events, anticipated or modeled violations, existing and planned visibility and measurement (feeder-level and time) data, monitoring and control capabilities, daytime minimum load, and other characteristics as necessary to allow the Commission and stakeholders to analyze system data for the purposes of achieving the goals of this Section;

(J) distributed energy resource deployment by type, size, customer class, and geographic dispersion; and

(K) total number and nameplate capacity of distributed energy resources that completed interconnection to the system in each of the prior 5 years, including average time to process interconnection applications for each type of resource and interconnection level.

(ii) Distribution System Planning Process. A detailed description of the electric utility's distribution system planning process including, but not limited to: any process required by a regional transmission organization; forecasts, inputs and assumptions of future total load and future peak demand; planned infrastructure investments and underlying assumptions regarding the necessity of such investments; and other relevant details for the 10-year planning horizon.

(iii) Hosting Capacity and Interconnection Analysis. A hosting capacity analysis which includes a detailed and current analysis of how much capacity is available on each substation, circuit and node for integrating renewable and distributed energy resources as allowed by thermal ratings, protection system limits, power quality standards, and safety standards. This section must include: circuit-level maps and downloadable data sets for public use; an assessment of how anticipated investments (for as far into the future as the utility has planned investments) will impact the analysis; and a narrative discussion of how the hosting capacity analysis advances customer-sited distributed energy resources, including in particular electric vehicles, electric storage systems and photovoltaic resources.

(iv) Scenario Analysis and Load Forecasting. Detailed load forecasts for the following 10 years at the substation and circuit level, using dynamic load forecasting (forecasting using multiple scenarios and probabilistic planning) and accounting for the impacts of anticipated energy efficiency programs, demand response programs, distributed energy resources, electric vehicle adoption, and other known or anticipated variables. This section shall also include a detailed description of the electric utility's anticipated capacity, thermal, voltage or other grid constraints for the following 3-year period, including modifications or upgrades to the system required to accommodate anticipated future load and distributed energy resource adoption. This section shall also include a discussion of the development of base-case, medium and high scenarios of distributed energy resource deployment, reflecting a reasonable mix of individual distributed energy resource adoption and aggregated or bundled distributed energy resource service types, and detailed information on the methodologies used to develop those scenarios.

(v) Grid Value Analysis. An evaluation of the short- and long-run benefits and costs of distributed energy resources located on the distribution system, including, but not limited to, the locational, temporal, and performance-based benefits and costs of distributed energy resources. This evaluation shall be based on the reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, avoided or increased line-losses, voltage support and ancillary services, safety benefits, reliability benefits, resilience benefits, and any other savings, benefits or value the distributed energy resources individually or in aggregate provide to the distribution system or costs to ratepayers of the electric utility. The utility shall use the results of this evaluation to inform its analysis of Solution Sourcing

Opportunities, including nonwires alternatives, under subparagraph (viii) of this paragraph (2). The Commission may use the data produced through this evaluation to, among other use-cases, establish tariffs and compensation for distributed energy resources interconnecting to the utility's distribution system, including rebates provided by the electric utility pursuant to Section 16-107.6 of this Act.

(vi) Utility System Investment Plan. A detailed description of historic distribution system capital investments for the preceding 5 years and planned capital investments for the following 10 years, as well as load forecasts and all other data supporting those investments. This section shall include projected costs, scope of work, prioritization of work, sequencing of investments, and explanations of how planned investments will meet the objectives described in subsection (d).

(vii) Utility Operations Plan. A detailed description of historic distribution system operations and maintenance expenditures for the preceding 5 years and of planned operations and maintenance expenditures for the following 10 years, as well as the data, reasoning and explanation supporting planned expenditures. This section shall also include a description of total costs spent on distributed energy resource interconnection review and commissioning (including application review, responding to inquiries, metering, testing and other costs), as well as interconnection fees and charges to customers and installers of distributed energy resources, including (application, metering and make-ready fees), broken down by type of generation and category or level of interconnection review, over each of the preceding 5 years.

(viii) Solution Sourcing Opportunities. Identification of potential cost-effective solutions from nontraditional and third-party owned investments that could meet anticipated grid needs, including, but not limited to: distributed energy resource procurements, tariffs or contracts, programmatic solutions, rate design options, technologies or programs that facilitate load flexibility, nonwires alternatives, and other solutions that are intended to meet the objectives described at subsection (d). It is the policy of this State that cost-effective third-party or customer-owned distributed energy resources shall be prioritized because those resources create robust competition and customer choice.

(ix) Interoperability Plan. A detailed description of the utility's interoperability plan, which must describe the manner in which the electric utility's current and planned distribution system investments will work together and exchange information and data, the extent to which the utility is implementing open standards and interfaces with third-party distributed energy resource owners and aggregators, and the utility's plan for interoperability testing and certification.

(x) Flexibility Analysis. A detailed analysis of current and projected flexible resources, including resource type, size (in MW and MWh), location and environmental impact, as well as anticipated needs that can be met using flexible resources (including, but not limited to, peak load reduction, managing ramp needs, storing excess generation, and avoiding unnecessary transmission expenditures).

(xi) Equity Requirements. A description of, exclusive of low-income rate relief programs and other income-qualified programs, how the utility is ensuring that at least 40% of benefits from programs, policies, and initiatives proposed in their Multi-Year Integrated Grid Plan will be directed to ratepayers in low-income and environmental justice communities. This should include locational reporting, at the census-tract level, on distribution system investments, program participation, and reliability and service quality data.

(3) To the extent any information in utilities' Multi-Year Integrated Grid Plans is designated as confidential because disclosure of such threatens the security of critical system infrastructure, that information shall be redacted as necessary but made available to parties who agree in writing to abide by confidentiality requirements as approved by the Office of General Counsel of the Illinois Commerce Commission. Information appropriately designated as confidential shall only include that which is critical to system security, and shall not include that information in which the electric utility claims only a proprietary business interest.

(4) Comprehensive Consideration of Related Plans, Tariffs, Programs and Policies. It is the policy of this State that holistic consideration of all related investments, planning processes, tariffs, rate design options, programs, and other utility policies and plans shall be required. To that end, the Commission shall consider, comprehensively, the impact of all related plans, tariffs, programs and policies on the Plan and on each other, including:

(i) time-of-use pricing program, pursuant to Section 16-107.7 of this Act, hourly pricing program, pursuant to Section 16-107 of this Act, and any other time-variant or dynamic pricing program;

(ii) distributed generation rebate, pursuant to Section 16-107.6 of this Act;

(iii) net electricity metering, pursuant to Section 16-107.5 of this Act;

(iv) energy efficiency programs, pursuant to Section 8-103B of this Act;

(v) Electric Vehicle Access for All programs, pursuant to Section 30 of the Electric Vehicle Act;

(vi) beneficial electrification programs, pursuant to Section 16-107.8 of this Act;

(vii) other plans, programs and policies that are relevant to distribution grid investments, costs planning, etc.

The Plan shall comprehensively detail the relationship between these plans, tariffs, and programs and the Plan and to the electric utility's achievement of the objectives in subsection (d). The Plan shall be designed to coordinate each of these plans, programs and tariffs with the electric utility's long-term distribution system investment planning in order to maximize the benefits of each.

(5) Hearing Procedure. The Initiating Order for the Initial Multi-Year Integrated Grid Plan, as well as each electric utility's subsequent Integrated Grid Plans under subsection (g), shall begin a contested proceeding as

described in subsection (d) of Section 10-101.1 of this Act.

(i) In evaluating a utility's Plan, the Commission shall consider, at minimum, whether the Plan:

(A) meets the objectives of this Section;

(B) includes the components in paragraph (2) of subsection (f) of this Section;

(C) incorporates input from interested stakeholders, including parties and people who offer public comment;

(D) considers nontraditional and nonutility-owned investment alternatives that can meet grid needs and provide additional benefits (including consumer, economic and environmental benefits) beyond comparable, traditional utility-planned capital investments;

(E) equitably benefits environmental justice communities; and

(F) maximizes consumer, environmental, economic and community benefits.

(ii) The Commission, after notice and hearing, shall modify each electric utility's Plan as necessary to comply with the objectives of this Section. The Commission may approve, or modify and approve, a Plan only if it finds that the Plan is reasonable, complies with the objectives and requirements of this Section, and reasonably incorporates input from parties. The Commission's approval of any Plan does not constitute approval, or any adjudication of the prudence or reasonableness, of any expenditures associated with the Plan. The Commission may reject each electric utility's Plan if it finds that the Plan does not comply with the objectives and requirements of this Section. Where the Commission enters an Order rejecting a Plan, the utility must refile a Plan within 3 months after that Order, and until the Commission approves a Plan, the utility's existing Plan will remain in effect.

(iii) For all Integrated Grid Plan filings, the Commission shall enter an order no later than 9 months after the date of filing.

(iv) Each electric utility shall file its proposed Initial Multi-Year Integrated Grid Plan no later than June 1, 2022. Prior to that date and following the Initiating Order, the Commission shall initiate a case management conference and shall take any appropriate steps to begin meaningful consideration of issues, including enabling interested parties to begin conducting discovery.

(6) Implementation Plans.

(i) As part of its order approving a utility's Multi-Year Integrated Grid Plan, including any modifications required, the Commission shall create a subsequent implementation plan docket, or multiple implementation plan dockets, if the Commission determines that multiple dockets would be preferable, to consider the utility's detailed plans for:

(A) acquiring the level of demand response resources specified in its approved Multi-Year Integrated Grid Plan;

(B) acquiring the level of load flexibility or energy storage resources specified in its approved Multi-Year Integrated Grid Plan;

(C) achieving the level of transportation, building and industry electrification specified in its approved Multi-Year Integrated Grid Plan, or implementing optimized charging or other beneficial electrification programs;

(D) developing any of the plans, tariffs, programs or policies required by paragraph (4) of subsection (e) and additionally required by the Commission in its Order regarding the Multi-Year Integrated Grid Plan; and

(E) developing the Hosting Capacity and Interconnection Analysis required by paragraph (2) of subsection (f);

(F) developing a process to screen, analyze and procure nonwires alternatives; and

(G) addressing any other topic or resource area covered by the utility's Multi-Year Integrated Grid Plan for which the Commission considers it important and necessary to receive and approve a greater level of detail regarding the utility's plans.

(ii) Each implementation plan shall include a detailed explanation of:

(A) the projected costs (investments and expenses) and benefits of each plan or program to be considered in the implementation plan, including related financial incentives, marketing, and administration;

(B) categories and sub-categories of resources or services to be acquired to achieve the objectives in the Multi-Year Integrated Grid Plan (for example, the implementation plan for demand response shall identify the different types of demand response resources that will collectively be pursued to achieve the total level of demand response capability approved in the Plan);

(C) the marketing, customer recruitment and engagement, financial incentive, procurement approach and other important elements of the plan or program, including efforts to cultivate qualifying customers in low-income and environmental justice communities;

(D) an explanation of how the proposed plans or programs will be able to achieve the objective in the Multi-Year Integrated Grid Plan;

(E) an analysis of how, exclusive of low-income rate relief and other income-qualified programs, the implementation plan will contribute to the Multi-year Integrated Grid Plan's requirement that at least 40% of benefits from programs, policies, and initiatives will be directed to low-income and environmental justice communities;

(F) a discussion of any risk in the utility's ability to acquire the planned levels of resource acquisition within the approved budget, as well as contingency plans for addressing such risks; and

(G) a plan for periodic (but at least quarterly) engagement with stakeholders on the rollout and implementation of the implementation plans in order to inform them of plans and progress, as well as to solicit input on opportunities for improving plans and implementation or on ways to modify plans as needed.

(iii) The implementation plan dockets shall be contested proceedings, with opportunities for discovery and filing of testimony by interested stakeholders. Each utility shall file its implementation plans within 90 days after approval, with any modifications, of its Multi-Year Integrated Grid Plan.

(g) Subsequent Multi-Year Integrated Grid Plans. No later than June 1, 2025 and every 4 years thereafter, each electric utility subject to this Section shall file a new Multi-Year Integrated Grid Plan for the subsequent 4 delivery years after the completion of the then-effective Plan. Each Plan shall meet the requirements described in subsection (f), and shall be preceded by a workshop process which meets the same requirements described in subsection (e). If appropriate, the Commission may require additional implementation dockets to follow Subsequent Multi-Year Integrated Grid Plan filings.

(220 ILCS 5/16-107.7 new)

Sec. 16-107.7. Residential time-of-use pricing.

(a) The General Assembly finds that time-of-use rates and pricing plans can lower energy costs for consumers and reduce grid costs as well as help Illinois achieve its energy policy goals by improving load shape, encouraging energy conservation, and shifting usage away from periods where fossil fuels are used to meet peak demand. Further, by providing consumers information relating the costs of service to the time of energy usage, time-of-use rates can help consumers reduce their energy bills by using electricity when it is less costly. Time-of-use rates can help allocate electricity system costs more accurately and thus equitably to those who cause costs. Such rates can reduce the need for ramping resources and increase the grid's ability to cost-effectively integrate greater quantities of variable renewable energy and distributed energy resources.

(b) An electric utility that has a tariff in effect under Section 16-108.5 as of the effective date of this amendatory Act of the 102nd General Assembly shall also offer at least one market-based, time-of-use rate for eligible retail customers that choose to take power and energy supply service from the utility. The utility shall file its time-of-use rate tariff no later than 120 days after the effective date of this amendatory Act of the 102nd General Assembly, and each utility subject to this requirement shall implement the requirements of this paragraph by filing a tariff with the Commission. The tariff or tariffs shall be subject to the following provisions:

(1) If more than one tariff is proposed, at least one tariff shall include at least 3 time blocks: a peak time block defined as 2 p.m. to 7 p.m. on nonholiday weekdays or the 5 consecutive hours best reflecting the highest system peak demands, an off-peak time block defined as 10 a.m. to 2 p.m. and 7 p.m. to 10 p.m. on nonholiday weekdays or the 7 total hours, occurring in some combination before and

after the peak period, which reflect the next highest system peak demands, and a super-off-peak time block defined as all other hours including weekend days.

2) This tariff shall strive to achieve price ratios between the blocks as follows: the super-off-peak time block price shall be no less than zero but no greater than one-half of the price of the off-peak time block price, and the off-peak time block price shall be no greater than one-half of the price of the peak time block price.

(3) The time-of-use rate shall include the costs of electric capacity, costs of transmission services, and charges for network integration transmission service, transmission enhancement, and locational reliability, as these terms are defined in the PJM Interconnection LLC Open Access Transmission Tariff and manuals on January 1, 2019, within the prices for each time block and seasonal block in which the associated costs generally are incurred. If the Open Access Transmission Tariff or manuals subsequently renames those terms, the services reflected under those terms shall continue to be included in the time-of-use rate described in this paragraph (2).

(4) Adjustments to the charges set by the tariff may be made on a semi-annual basis, as follows: each May and November, the utility shall submit to the Commission, through an informational filing, its updated charges, and such charges shall take effect beginning with the June

monthly billing period and December monthly billing period, respectively.

(5) The tariff shall include a purchased energy adjustment to fully recover the supply costs for the customers taking service under this tariff.

"Eligible customers" includes, but is not limited to, customers participating in net electricity metering under the terms of Section 16-107.5.

(c) The Commission shall, after notice and hearing, approve the tariff or tariffs with modifications the Commission finds necessary to improve the program design, customer participation in the program, or coordination with existing utility pricing programs, energy efficiency programs, demand response programs, and any other programs supporting Illinois energy policy goals and the integration of distributed energy resources. The Commission shall also consider how the proposed time-of-use rate design reflects the system costs and usage patterns of the utility. A proceeding under this subsection may not exceed 120 days in length.

(d) If the Commission issues an order pursuant to this subsection, the affected electric utility shall contract with an entity not affiliated with the electric utility to serve as a program administrator to develop and implement a program to provide consumer outreach, enrollment, and education concerning time-of-use pricing and to establish and administer an information system and technical and other customer assistance that is necessary to enable customers to manage electricity use. The program administrator: (i) shall be selected and compensated by the electric utility, subject to Commission approval; (ii) shall have demonstrated technical and managerial competence in the development and administration of demand management programs; and (iii) may develop and implement risk management, energy efficiency, and other services related to energy use management for which the program administrator shall be compensated by participants in the program receiving such services. The electric utility shall provide the program administrator with all information and assistance necessary to perform the program administrator's duties, including, but not limited to, customer, account, and energy use data. The electric utility shall permit the program administrator to include inserts in residential customer bills 2 times per year to assist with customer outreach and enrollment.

The program administrator shall submit an annual report to the electric utility no later than April 1 of each year describing the operation and results of the program, including information concerning the number and types of customers using the program, changes in customers' energy use patterns, an assessment of the value of the program to both participants and nonparticipants, and recommendations concerning modification of the program and the tariff or tariffs filed under this Section. This report shall be filed by the electric utility with the Commission within 30 days after receipt and shall be available to the public on the Commission's website.

(e) Once the tariff or tariffs has been in effect for 24 months, the Commission may, upon complaint, petition, or its own initiative, open a proceeding to investigate whether changes or modifications to the tariff or tariffs, program administration and any other program design element is necessary to achieve the goals described in subsection (a) of this Section. Such a proceeding may not last more than 120 days from the date upon which the investigation is opened by Commission order.

(f) An electric utility shall be entitled to recover reasonable costs incurred in complying with this Section, provided that recovery of the costs is fairly apportioned among its residential customers.

(g) The electric utility's tariff or tariffs filed pursuant to this Section shall be subject to the provisions of Article IX of this Act insofar as they do not conflict with this Section.

(h) This Section does not apply to any electric utility providing service to 100,000 or fewer customers.

(220 ILCS 5/16-108.18 new)

Sec. 16-108.18. Performance-based ratemaking.

(a) Findings and Purpose. The General Assembly finds that improving the alignment of utility customer and company interests is critical to ensuring that Illinois residents and businesses have the opportunity to optimize existing utility infrastructure and do not suffer economic and environmental harm from the State's energy systems. This realignment is critical to ensure the ongoing viability of Illinois electric utilities, as they face an increasing need to rapidly adopt business models and strategies that enable new innovations and customer choices. Furthermore, the General Assembly finds that this realignment has entered a period of extraordinary urgency, given the expected rapid growth of distributed energy resources, electric vehicles, and other new technologies that substantially change the makeup of the grid. Moreover, urgency of action to address increasing threats from climate change and to assist communities that have borne a disproportionate impact from air pollution, greenhouse gas emissions, and energy burdens requires immediate and significant change to the business model under which utilities in Illinois have functioned. Providing incentive for necessary changes through a new holistic, performance-based structure for ratemaking will enable alignment of utility, customer, community and environmental goals. In particular, the General Assembly finds that:

(1) The traditional regulatory model rewards utilities for increasing capital expenditures by basing allowed revenues on the value of the rate base, irrespective of utility performance. This compact does not align the

interests of customers and utilities because it may result in a bias toward expending utility capital in ways that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by independent third parties that can meet grid needs.

(2) Traditional regulation also rewards utilities for selling higher volumes of electricity through the throughput incentive. This model unnecessarily increases customer costs and pollution and is therefore in neither ratepayers' nor the State's interest.

(3) Though Illinois has taken some measures to move utilities to performance-based ratemaking through the establishment of performance incentives and a performance-based formula rate under the Energy Infrastructure Modernization Act, these measures have not been transformative in urgently moving electric utilities toward the State's ambitious energy policy goals: protecting a healthy environment and climate, improving public health, and creating quality jobs and economic opportunities including wealth building, especially in economically disadvantaged communities and BIPOC communities. Rather, they have resulted in excess utility profits without meaningful improvements in customer experience, rates, or equity.

(4) The General Assembly therefore directs the

Illinois Commerce Commission to complete a transition to a comprehensive performance-based regulation framework for electric utilities with more than 500,000 customers. The breadth of this framework should remake existing utility regulations to position Illinois electric utilities to effectively and efficiently achieve current and anticipated future energy needs of this State.

(5) It is the intent of the General Assembly that over time the comprehensive performance-based regulation framework will progressively reduce the direct link between utility revenues and traditional investment levels and increasingly tie revenues to performance.

(b) Definitions.

As used in this Section:

"Commission" means the Illinois Commerce Commission.

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

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

"Economically disadvantaged communities" means areas of one or more census tracts where average household income does not exceed 80% of area median income.

"Environmental justice communities" means the definition of that term based on existing methodologies and findings, used and as may be updated by the Illinois Power Agency and its Program Administrator in the Illinois Solar for All Program.

"Performance-based regulation or ratemaking" or "PBR" means a regulatory approach that aligns utility interests with customer and societal interests through regulatory mechanisms that motivate utilities to improve operations, increase program effectiveness, better manage business expenses, and align system performance with identified societal or policy goals.

(c) Objectives. The comprehensive PBR framework should be designed to accomplish the following objectives:

(1) incentivize utilities to pursue cost-effective solutions to meet customer needs;

(2) decarbonize utility systems at a pace that meets or exceeds state climate goals;

(3) remove utility incentives to grow energy sales, except where sales growth is determined to be aligned with state policy goals;

(4) reduce the link between utility expenditures and collected revenue and eliminate embedded utility preferences for one type of expenditure over another for the same service;

(5) incentivize utilities to undertake the most

effective expenditures for assets or services, whether self-supplied by the utility or through third-party contracting, to deliver high-quality service to customers at least cost;

(6) maintain the affordability, safety, and reliability of electric power supply; and

(7) incentivize utilities to pursue equitable access to high-quality customer service, affordable rates, DER interconnection, and the benefits of grid modernization and clean energy for ratepayers in environmental justice and economically disadvantaged communities. Additionally, motivate utilities to sustain a diverse workforce, supplier procurement base and, for relevant programs, approved vendor pools.

(d) The comprehensive PBR framework should comprise a set of PBR mechanisms that collectively accomplish the objectives set forth in subsection (c). Those mechanisms may include, but are not limited to:

(1) Multi-Year Rate Plans and associated features, as set forth in subsection (e) of this Section;

(2) revenue decoupling, as set forth in paragraph (11) of subsection (e) of this Section;

(3) shared savings mechanisms;

(4) performance incentive mechanisms, as set forth in subsection (f) of this Section;

(5) changes to the accounting treatment of capital and

operating expenditures; and

(6) changes to rate design, as set forth in Section paragraph 10 of subsection (e) of this Section.

(e) Multi-Year Rate Plan.

(1) If an electric utility has a performance-based formula rate in effect under Section 16-108.5 as of December 31, 2020, then the utility shall file a petition proposing tariffs implementing a 4-year Multi-Year Rate Plan as provided in this Section no later than July 1, 2022 for delivery service rates to be effective from June 1, 2023 through May 31, 2027. The Commission shall issue an order approving, approving as modified, or rejecting the utility's plan no later than June 1, 2023. If the Commission rejects the utility's plan, the deadline to approve the plan or approve it as modified shall be extended to 4 months from the date of the rejection. The term "Multi-Year Rate Plan" refers to a plan establishing the rates the utility may charge for each delivery year of the 4-year period to be covered by the plan. The net revenue requirement reflected in rates in effect on December 31, 2021 for the electric utility shall remain in effect until new rates are approved under the Multi-Year Rate Plan, and no additional annual reconciliation under Section 16-108.5 shall be made.

(2) A utility proposing a Multi-Year Rate Plan shall provide a description of the utility's major planned

investments, which shall include at a minimum all investments of $1,000,000 or greater over the plan period. Planned investments must conform to the goals established in the Multi-Year Integrated Grid Plan described in Section 16-105.17 of this Act.

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

(A) Provide for the recovery of the utility's forecasted rate base, based on a budget forecast or a fixed escalation rate, individually or in combination. The forecasted rate base must include the utility's planned capital investments and investment-related costs, including income tax impacts, depreciation, and property taxes prudently incurred and reasonable in amount consistent with Commission practice and law. The budgeting process must be iterative, be rigorous, and lead to forecasts that reasonably represent the utility's investments during the forecasted period.

(B) For the first Multi-Year Rate Plan, reflect year-end capital structure that includes a common equity ratio, excluding goodwill, of no more than 50% of the total capital structure shall be deemed reasonable and prudent and used to set rates.

(C) For the first Multi-Year Rate Plan, include a cost of equity, which shall be calculated as the sum of the following:

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

(ii) 530 basis points.

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

(D) For subsequent Multi-Year Rate Plans, the cost of equity and capital structure shall be established by the Commission and shall be set to reflect a risk-adjusted return compared to the prevailing cost of capital and comparable investments in the economy, including U.S. Treasury rates, upon which additional earning opportunities and penalties can be provided to reflect utility performance against identified outcomes.

(E) Recovery of operations and maintenance expenses, based on projected costs, an electricity-related price index or other formula.

(F) Amortize the amount of unprotected property-related excess accumulated deferred income taxes in rates as of December 31, 2022 over a period of 5 years.

(G) Disallow recovery of charitable contributions.

(H) Allow recovery of pension and other post-employment benefits expense only if such costs are demonstrated to be funded by ratepayers.

(I) Allow recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, environmental compliance and attainment of environmental goals, and other goals and metrics approved by the Commission. Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable;

(4) Rates charged under the Multi-Year Rate Plan must be based only upon the utility's reasonable and prudent costs of service over the term of the plan, as determined by the Commission, provided that the costs are not being recovered elsewhere in rates. Rate adjustments authorized by the Commission may continue outside of a plan authorized under this Section to the extent such costs are not recovered elsewhere in rates. The burden of proof shall be on the electric utility to establish the prudence of investments and expenditures and to establish that such investments are reasonably necessary to meet the requirements of the most recently approved Multi-Year Integrated Grid Plan described in Section 16-105.17 of this Act. The sole fact that a cost differs from that incurred in a prior period or that an investment is different from that described the Multi-year Integrated Grid Plan shall not imply the imprudence or unreasonableness of that cost or investment. The sole fact that an investment is the same or similar to that described in the Multi-Year Integrated Grid Plan shall not imply prudence and reasonableness.

(5) To facilitate public transparency, all materials, data, testimony, schedules, etc. shall be provided to the Commission in an editable, machine-readable electronic format including .doc, .docx, .xls, .xlsx, and similar,

<u>but not including .pdf or .exif. Should utilities designate any materials "confidential," they shall have an affirmative duty to explain why the particular information is marked confidential. In determining prudence and reasonableness of rates, the Commission shall also consider each public comment filed in the docket.</u>

<u>(6) The Commission may, by order, establish terms, conditions, and procedures for a Multi-Year Rate Plan necessary to implement this Section and ensure that rates remain just and reasonable during the course of the plan, including terms and procedures for rate adjustment. At any time prior to conclusion of a Multi-Year Rate Plan, the Commission, upon its own motion or upon petition of any party, may initiate a proceeding to examine the reasonableness of the utility's rates under the plan, and adjust rates as necessary.</u>

<u>(7) Capital True-up. The utility shall propose an annual capital true-up mechanism that provides a refund to customers if the utility's actual capital-related revenue requirement is less in total in any of the Multi-Year Rate Plan delivery years than the Commission authorizes for that year. Conversely, if the Company's actual capital-related revenue requirement is more in total in the Multi-year Rate Plan delivery year than the Commission authorizes for that year, the Company cannot surcharge customers to collect any under recovery.</u>

(8) A participating utility that files a tariff pursuant to paragraph (3) of this subsection (e) must submit a one-time $200,000 filing fee at the time the Chief Clerk of the Commission accepts the filing, which shall be a recoverable expense.

(9) Subsequent Multi-Year Rate Plans. An electric utility operating under the Multi-Year Rate Plan shall file a new Multi-Year Rate Plan at least 210 days prior to the end of the initial Multi-Year Rate Plan, and every 4 years thereafter, with a rate-effective date of the proposed tariffs such that, after the Commission suspension period, the rates would take effect immediately at the close of the final year of the initial Multi-Year Rate Plan. In subsequent Multi-Year Rate Plans, as in the initial plans, utilities and stakeholders may propose additional metrics that achieve the outcomes described in paragraph (2) of subsection (f) of this Section.

(10) Rate Design. The Commission shall approve tariffs as part of each Multi-Year Rate Plan establishing rate design for all delivery service customers. These shall expand the rate options available to customers, including, but not limited to, an affordability rate for low-income residential customers, a time-of-use rate, an electric vehicle rate, and a peak time savings rate.

(11) Decoupling. The Commission may, by order, approve a tariff filed by an electric utility that provides for

decoupling of sales and revenues to mitigate the impact on public utilities of the energy-savings goals and to reduce a utility's disincentive to promote energy efficiency under Section 16-111.5B of this Act without adversely affecting utility ratepayers. In its consideration of a proposed decoupling tariff, the Commission shall consider a mechanism that triggers the periodic adjustment to rates when the changes in revenue would result in a change within a certain percentage, an earnings band to share revenues that exceed the authorized return, or other mechanisms that reduce the size and frequency of rate adjustments.

(f) Performance Incentive Mechanisms.

(1) The Commission shall establish performance incentive mechanisms in order to better tie utility revenues to performance and customer benefits, accelerate progress on Illinois energy and other goals, and hold utilities publicly accountable. The Commission shall develop metrics, which are observable and measurable indicators of system or utility performance, in order to create performance incentive mechanisms. Specifically, the Commission shall establish:

(A) Tracking metrics, which will be used for measuring and reporting utility performance.

(B) Performance metrics, which will be used for financially incentivizing improved utility performance.

(2) Outcomes of Metrics. The Commission shall approve tracking and performance metrics that encourage cost-effective, equitable utility achievement of the following outcomes:

(A) Affordability. Achieve affordable customer energy costs and utility bills, with particular emphasis on keeping lower-income households' bills within a manageable portion of their income.

(B) Pollution Reduction. Minimize emissions of greenhouse gases and pollutants that harm human health, particularly in environmental justice and economically disadvantaged communities, through both (A) minimizing emissions per kilowatt-hour of electricity consumed; and (B) minimizing total emissions, including by accelerating electrification of transportation, buildings and industries where such electrification results in net reductions, across all fuels and over the life of electrification measures, of greenhouse gases and other pollutants.

(C) Flexibility. Enhance the grid's flexibility to adapt to increased deployment of nondispatchable resources; improve the ability and performance of the grid on load balancing; and address uncertainty around future customer needs, future environmental concerns, emerging technology, changes in costs of technology and service, and other factors.

(D) Reliability. Meet high standards of overall and locational reliability.

(E) Customer Experience. Deliver customer service quality, customer engagement, and customer access to utility system information.

(F) Equity. Maximize and prioritize the allocation of grid planning benefits to environmental justice and economically disadvantaged customers and communities. Sustain a diverse workforce, supplier procurement base and, for relevant programs, approved vendor pools.

(G) Cost-effectiveness. Ensure rates reflect cost savings attributable to grid modernization and integration of distributed energy resources that allow the utility to defer or forgo traditional grid investments that would otherwise be required.

It is the intent of the General Assembly that these outcomes shall guide the development of metrics even as the grid, along with its associated technologies and policies, evolves. It is also the intent of the General Assembly that the limitation of total costs to customers and the promotion of ethical and transparent practices by utilities, as well as the role that flexible load and distributed energy resources can play in advancing the outcomes, be considered in the establishment of metrics.

(3) Metrics Requirements.

(A) Tracking Metrics. Tracking metrics shall entail a description of the metric, a calculation method, and a data collection method. The Commission shall approve tracking metrics that measure achievement of at least one of the outcomes set forth in paragraph (2) and are supported by sufficient stakeholder input. Tracking metrics should measure outcomes and actual results and projections where possible.

(B) Performance Metrics. Performance metrics shall entail a description of the metric, a calculation method, a data collection method, annual binding performance targets, and monetary incentives (rewards or penalties or both, depending on the metric) for utilities' achievement of or failure to achieve their performance targets. The Commission shall approve performance metrics that (i) measure achievement of the outcomes set forth in paragraph (2); (ii) are supported by sufficient stakeholder input; (iii) have one year of tracking data collected in a consistent manner and verifiable by an independent evaluator in order to establish a baseline; and (iv) require an incentive (reward or penalty or both) to create improved utility performance. While a single performance metric may measure achievement of more than one of the outcomes set forth in paragraph (2), and such metrics should be valued, the Commission shall not approve multiple performance metrics that measure achievement identical or near-identical results. Performance metrics should measure outcomes and actual, rather than projected, results where possible.

(C) Performance targets. For metrics where progressive improvement is desirable, performance targets shall increase annually and shall require utilities to perform beyond "business as usual," as determined by baseline tracking data and high-confidence projections. Increases to a target shall be considered in light of other metrics, cost-effectiveness, and other factors the Commission deems appropriate.

(D) Performance incentives. The Commission shall determine whether and to what extent each performance metric shall offer a reward, penalty, or both to a utility. For metrics where a reward is offered, and that reward is a cash payment, the reward shall be calculated as a percentage of net benefits from the outcome, net of costs to customers. The Commission shall develop a methodology to calculate net benefits that includes societal costs and benefits.

In determining the appropriate level of a reward or penalty, the Commission shall consider: the extent to which the amount is likely to encourage the utility to achieve the performance target in the least cost manner; the value of benefits to customers, the grid, and the environment from achievement of the performance target, including in particular benefits to environmental justice and economically disadvantaged communities; customer bill affordability; the utility's revenue requirement; and other such factors that the Commission deems appropriate. The consideration of these factors shall result in an incentive level that ensures benefits exceed costs for customers.

The rewards or penalties shall be calculated based on the electric utility achieving performance targets. In determining the specific rewards or penalties, the Commission shall give proportionate weight to the following set of metrics: affordability, cost-effectiveness, pollution reduction, flexibility, customer experience, reliability, and equity.

It is the intent of the General Assembly that over time the utility's cost of equity shall be progressively reduced while the opportunity to grow earnings as a result of achieving performance targets shall be progressively increased as the Commission establishes new performance metrics.

(g) Initial Metrics. The Commission shall initiate a

4-month workshop process no later than March 1, 2022 for the purpose of informing the enactment of metrics. The workshop shall be facilitated by Staff of the Illinois Commerce Commission, and shall be organized and facilitated in a manner that encourages representation from diverse stakeholders, ensuring equitable opportunities for participation, without requiring formal intervention or representation by an attorney. Following the workshop, the Commission shall establish initial tracking and performance metrics in a docketed proceeding that shall be filed by the electric utility by July 2, 2022. The initial tracking and performance metrics shall be in place for the period of the first Multi-Year Rate Plan. The proceeding shall conclude, and the commission shall issue an order in the matter, no later than April 1, 2023.

Unless the tracking metrics in subparagraph (3) of paragraph (A) and performance metrics in subparagraph (3) of paragraph (B) of subsection (f) of this Section are found by the Commission during initial metric-setting proceeding to not meet the requirements set forth in this Section, the Commission shall approve these metrics, and it shall establish calculations and goals for the tracking metrics set forth in subparagraph (3) of paragraph (A) of subsection (f) of this Section and calculations, targets, and incentives for the tracking metrics set forth in subparagraph (3) of paragraph (B) of subsection (f) of this Section. If the Commission finds that the metrics set forth in subparagraph (3) of paragraph (A) and subparagraph (3) of paragraph (B) of subsection (f) of this Section do not meet the requirements set forth in this Section, then the Commission shall approve substitute metrics. The Commission may also approve additional tracking and performance metrics as appropriate if they meet the requirements set forth in this Section.

Initial Performance Metrics shall include at a minimum, but not limited to, the following:

(1) system Average Interruption Frequency Index;

(2) customer Average Interruption Duration Index; and

(3) peak load reductions enabled by demand response programs.

(h) Future Metrics. The Commission shall establish new tracking and performance metrics in future Annual Performance Evaluation proceedings to further measure achievement of the outcomes set forth in paragraph (2) of subsection (f) of this Section and the other goals and requirements of this Section.

The Commission shall also evaluate metrics that were established in prior Annual Performance Evaluation proceedings under the procedures set forth in subsection (i) to determine if adjustments are required to improve the likelihood of the outcomes described in paragraph (2) of subsection (f). For metrics that were established in prior Annual Performance Evaluation proceedings and that the Commission elects to continue, the design of these metrics, including the goals of tracking metrics and the targets and incentive levels and structures of performance metrics, may be adjusted pursuant to the requirements in this Section. The Commission may also phase out tracking and performance metrics that were established in prior Annual Performance Evaluation proceedings if these metrics no longer meet the requirements of this Section or if they are rendered obsolete by the changing needs and technology of an evolving grid. Additionally, performance metrics that no longer require an incentive to create improved utility performance may become tracking metrics.

In service of the outcomes set forth in paragraph (2) of subsection (f), it is the intent of the General Assembly that the Commission in future Annual Performance Evaluation proceedings establish the tracking metrics and performance metrics set forth in subparagraph (A) and subparagraph (B) of paragraph (3) of subsection (f) of this Section when these metrics would be compliant with the requirements set forth in this Section.

(i) Annual Performance Evaluation. On June 1 of each year, following the approval of the first Multi-Year Rate Plan and its initial delivery year, the Commission shall open an Annual Performance Evaluation proceeding to evaluate the utilities' performance on their metric targets during the delivery year just completed and accordingly determine rewards or penalties or both to be reflected in rates in the following calendar year.

(1) Utility Reporting. On April 1 of each year, prior to the Annual Performance Evaluation proceeding, each participating utility shall file a Performance Evaluation Report with the Commission that includes a description of and all data supporting how the participating utility performed under each tracking and performance metric and an identification of any extraordinary events that adversely impacted the utility's performance. The Performance Evaluation Report shall be verified by an independent evaluator as set out in paragraph (3) of this subsection (i) and shall include both a report made to the Commission and a short, public-facing scorecard that makes this information publicly accessible and easily understandable. The Commission shall post each scorecard upon receipt on the Commission's web page in an easily-accessible location. The format of the report and the scorecard shall be consistent across utilities and shall include:

(A) a list of metrics to which the utility is subject;

(B) the previous delivery year's calculation methods and performance on metrics if applicable;

(C) the current delivery year's calculation methods and a detailed description of the effect of any differences;

(D) the current-year goals for tracking metrics and current-year targets for performance metrics;

(E) the current year's performance on metrics targets;

(F) a summary of the investments and programs undertaken in order to achieve those metrics targets; and (G) the annual goals and targets for the remaining years of the current Multi-Year Rate Plan period.

Within 30 days after the Commission's Order in the utility's Annual Performance Evaluation and Adjustment filing, the utility shall update the public scorecard with any changes required by the Commission and the revised scorecard shall be posted on the Commission's website.

(2) Public Workshops. Preceding each Annual Performance Evaluation, no later than April 1 each year, the Commission shall initiate a two-month workshop process. The workshops shall be facilitated by Staff of the Illinois Commerce Commission, and shall be organized and facilitated in a manner that encourages representation from diverse stakeholders, ensuring equitable opportunities for participation, without requiring formal intervention or representation by an attorney. During these workshops, each electric utility shall publicly present its performance on tracking and performance metrics following the requirements set forth in paragraph (1) of this subsection (i). The electric utility shall also explain how it has holistically considered the plans,

programs, tariffs and policies and its Multi-Year Integrated Grid Plan in order to achieve its metric targets. Members of the public shall have opportunity for comment and feedback. A summary of that feedback shall be provided in an exhibit submitted by Staff of the Illinois Commerce Commission in the Annual Performance Evaluation.

(3) Independent Evaluation. The electric utility shall provide for an annual independent evaluation of its performance on metrics. The independent evaluator shall review the utility's assumptions, baselines, targets, calculation methodologies, and other relevant information, especially ensuring that the utility's data for establishing baselines matches actual performance, and shall provide a Report to the Commission in each Annual Performance Evaluation describing the results. The independent evaluator shall present this Report as evidence as a nonparty participant. The independent evaluator shall be hired through a competitive bidding process.

The Commission shall consider the Report of the independent evaluator in determining the utility's achievement of performance targets. Discrepancies between the utility's assumptions, baselines, targets, or calculations and those of the independent evaluator shall be closely scrutinized by the Commission. If the Commission finds that the utility's reported data for any metric or metrics significantly deviates from the data reported by the independent evaluator, then the Commission shall order the utility to revise its data collection and calculation process within 60 days, with specifications where appropriate.

(4) Performance Adjustment. The Commission shall, after notice and hearing in the Annual Performance Evaluation proceeding, enter an order approving the utility's performance adjustment based on its achievement of or failure to achieve its performance targets no later than December 31 each year. The Commission-approved penalties or rewards shall be applied beginning with the next calendar year. Nothing in this Section shall authorize the Commission to reduce or otherwise obviate the imposition of financial rewards or penalties for achieving or failing to achieve one or more of the utility's performance targets.

(5) Revisions to Metrics. While tracking and performance metrics, along with their associated goals, targets, and incentives, shall not be changed outside of the Annual Performance Evaluation, the Commission may open an investigation into the methodology, including assumptions and calculations, used to measure or quantify progress toward goals and targets in the Annual Performance Evaluation at the request of an intervening party.

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

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Statutes amended in order of appearance