



102ND GENERAL ASSEMBLY

State of Illinois

2021 and 2022

HB2619

Introduced 2/19/2021, by Rep. Theresa Mah

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.

LRB102 16956 SPS 22373 b

FISCAL NOTE ACT
MAY APPLY

A BILL FOR

1 AN ACT concerning regulation.

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

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

6 Section 5. Findings. The General Assembly finds that:

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

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

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

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

21 Section 10. Definitions. As used in this Act:

22 "Commission" means the Illinois Commerce Commission.

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

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

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

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

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

8 "Customer" means any of the following:

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

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

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

21 (4) an organization representing environmental justice
22 communities.

23 "Customer" does not include any state, federal, or local
24 governmental agency, or any publicly owned public utility.

25 "Customer" must be a nonprofit organization.

26 "Environmental justice communities" means the definition

1 of that term based on existing methodologies and findings,
2 used and as may be updated by the Illinois Power Agency and its
3 program administrator in the Illinois Solar for All Program.

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

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

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

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

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

22 Section 15. Intervenor compensation awards. The Commission
23 shall award reasonable advocate's fees, reasonable expert
24 witness fees, and other reasonable costs of preparation for
25 and participation in a hearing or proceeding to any customer

1 that complies with the procedures in Section 20 and satisfies
2 both of the following requirements:

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

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

9 Section 20. Intervenor compensation award procedures.

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

15 (i) no prehearing conference is scheduled;

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

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

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

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

25 (A) A statement of the nature and extent of the

1 customer's planned participation in the proceeding as far
2 as it is possible to set it out when the notice of intent
3 is filed.

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

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

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

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

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

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

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

25 (d) The Commission may audit the records and books of the
26 customer to the extent necessary to verify the basis for the

1 award. The Commission shall preserve the confidentiality of
2 the customer's records in making its audit. Within 20 days
3 after completion of the audit, if any, the Commission shall
4 direct that an audit report shall be prepared and filed. Any
5 other party may file a response to the audit report within 20
6 days thereafter.

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

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

24 Section 30. Intervenor compensation payments and cost

1 recovery. An award made under this Act shall be paid by the
2 public utility that is the subject of the hearing,
3 investigation, or proceeding, as determined by the Commission,
4 within 30 days. Notwithstanding any other law, an award paid
5 by a public utility pursuant to this Act shall be allowed by
6 the Commission as an expense for the purpose of establishing
7 rates of the public utility.

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

12 Section 40. Illinois Commerce Commission Intervenor
13 Compensation Fund. The Illinois Commerce Commission Intervenor
14 Compensation Fund is hereby created as a special fund in the
15 State treasury. The Commission shall administer the Illinois
16 Commerce Commission Intervenor Compensation Fund for use as
17 described in Section 45. An electric public utility with
18 3,000,000 or more retail customers shall contribute \$450,000
19 to the Illinois Commerce Commission Intervenor Compensation
20 Fund within 60 days after the effective date of this Act. A
21 combined electric and gas public utility serving fewer than
22 3,000,000 but more than 500,000 retail customers shall
23 contribute \$225,000 to the Illinois Commerce Commission
24 Intervenor Compensation Fund within 60 days after the

1 effective date of this Act. A gas public utility with
2 2,000,000 or more retail customers that is not a combined
3 electric and gas public utility shall contribute \$225,000 to
4 the Illinois Commerce Commission Intervenor Compensation Fund
5 within 60 days after the effective date of this Act. A gas
6 public utility with fewer than 2,000,000 retail customers but
7 more than 300,000 retail customers that is not a combined
8 electric and gas public utility shall contribute \$80,000 to
9 the Illinois Commerce Commission Intervenor Compensation Fund
10 within 60 days after the effective date of this Act. A gas
11 public utility with fewer than 300,000 retail customers that
12 is not a combined electric and gas public utility shall
13 contribute \$20,000 to the Illinois Commerce Commission
14 Intervenor Compensation Fund within 60 days after the
15 effective date of this Act.

16 Section 45. Intervenor compensation pre-proceeding grants.

17 (a) Any customer that applies for intervenor compensation
18 payments under subsection (a) of Section 20 may also, at the
19 same time, apply for a grant from the Illinois Commerce
20 Commission Intervenor Compensation Fund for the costs
21 described in its notice of intent to claim compensation. A
22 final decision regarding the grant shall be made at the time of
23 the preliminary ruling on intervenor compensation eligibility
24 in subsection (b) of Section 20. No pre-proceeding grant shall
25 be given to organizations who are not found to be eligible for

1 intervenor compensation. If granted, payments must be made
2 within 30 days to facilitate participation in the proceeding.
3 At the time of the final decision regarding the grant, the
4 Commission shall notify the customer of the requirements to be
5 awarded intervenor compensation and that, if the customer does
6 not prevail in receiving intervenor compensation of at least
7 the amount of the grant, the customer will be expected to
8 reimburse the Illinois Commerce Commission Intervenor
9 Compensation Fund for the remaining grant moneys on a regular
10 schedule within 5 years of the end of the proceeding. After
11 notification, the customer may accept or deny receipt of the
12 grant.

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

20 (c) If a customer that receives a grant from the Illinois
21 Commerce Commission Intervenor Compensation Fund subsequently
22 prevails in receiving intervenor compensation, the public
23 utility paying intervenor compensation must reimburse the fund
24 for the amount of the grant. If the intervenor compensation
25 amount is larger than the grant, then the balance shall be paid
26 to the customer. If the amount of intervenor compensation is

1 less than the grant, then the customer must reimburse the
2 Illinois Commerce Commission Intervenor Compensation Fund for
3 the difference with payments made on a regular schedule within
4 5 years after the end of the proceeding.

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

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

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

19 (5 ILCS 100/5-45.8 new)

20 Sec. 5-45.8. Emergency rulemaking; Public Utilities
21 Intervenor Compensation Act. To provide for the expeditious
22 and timely implementation of the Public Utilities Intervenor
23 Compensation Act, emergency rules may be adopted in accordance

1 with Section 5-45 by the Illinois Commerce Commission to
2 implement the Public Utilities Intervenor Compensation Act.
3 The adoption of emergency rules authorized by Section 5-45 and
4 this Section is deemed to be necessary for the public
5 interest, safety, and welfare.

6 This Section is repealed on January 1, 2027.

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

9 (30 ILCS 105/5.935 new)

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

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

16 (220 ILCS 5/2-107) (from Ch. 111 2/3, par. 2-107)

17 Sec. 2-107. The office of the Commission shall be in
18 Springfield, but the Commission may, with the approval of the
19 Governor, establish and maintain branch offices at places
20 other than the seat of government. Such office shall be open
21 for business between the hours of 8:30 a.m. and 5:00 p.m.
22 throughout the year, and one or more responsible persons to be

1 designated by the executive director shall be on duty at all
2 times in immediate charge thereof.

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

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

25 The Commission may, for the authentication of its records,
26 process and proceedings, adopt, keep and use a common seal, of

1 which seal judicial notice shall be taken in all courts of this
2 State; and any process, notice, order or other paper which the
3 Commission may be authorized by law to issue shall be deemed
4 sufficient if signed and certified by the Chairman of the
5 Commission or his or her designee, either by hand or by
6 facsimile, and with such seal attached; and all acts, orders,
7 proceedings, rules, entries, minutes, schedules and records of
8 the Commission, and all reports and documents filed with the
9 Commission, may be proved in any court of this State by a copy
10 thereof, certified to by the Chairman of the Commission, with
11 the seal of the Commission attached.

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

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

18 (220 ILCS 5/4-605 new)

19 Sec. 4-605. Restitution for misconduct.

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

1 that details violations of criminal law.

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

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

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

3 (1) 25% shall be contributed to expand the Percentage
4 of Income Payment Program;

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

8 (220 ILCS 5/9-220.3)

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

10 Sec. 9-220.3. Natural gas surcharges authorized.

11 (a) Tariff.

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

19 (2) Within 30 days after the effective date of this
20 amendatory Act of the 98th General Assembly, the
21 Commission shall adopt emergency rules to implement the
22 provisions of this amendatory Act of the 98th General
23 Assembly. The utility may file with the Commission tariffs
24 implementing the provisions of this amendatory Act of the
25 98th General Assembly after the effective date of the

1 emergency rules authorized by subsection (i).

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

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

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

6 (5) A natural gas utility that is subject to its
7 delivery base rates being fixed at their current rates
8 pursuant to a Commission order entered in Docket No.
9 11-0046, notwithstanding the effective date of its tariff
10 authorized pursuant to this Section, shall reflect in a
11 tariff surcharge only those projects placed in service
12 after the fixed rate period of the merger agreement has
13 expired by its terms.

14 (b) For purposes of this Section, "qualifying
15 infrastructure plant" includes only plant additions placed in
16 service not reflected in the rate base used to establish the
17 utility's delivery base rates. "Costs associated with
18 investments in qualifying infrastructure plant" shall include
19 a return on qualifying infrastructure plant and recovery of
20 depreciation and amortization expense on qualifying
21 infrastructure plant, net of the depreciation included in the
22 utility's base rates on any plant retired in conjunction with
23 the installation of the qualifying infrastructure plant.
24 Collectively the "qualifying infrastructure plant" and "costs
25 associated with investments in qualifying infrastructure
26 plant" are referred to as the "qualifying infrastructure

1 investment" and that are related to one or more of the
2 following:

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

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

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

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

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

26 (B) the communications hardware and software and

1 associated system software that creates a network
2 between advanced gas meters and utility business
3 systems and allows the collection and distribution of
4 gas-related information to customers and other parties
5 in addition to providing information to the utility
6 itself;

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

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

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

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

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

7 (1) operating and maintenance costs; and

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

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

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

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

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

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

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

24 (e) Review of investment.

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

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

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

26 (f) The rate of return applied shall be the overall rate of

1 return authorized by the Commission in the utility's last gas
2 rate case.

3 (g) The cumulative amount of increases billed under the
4 surcharge, since the utility's most recent delivery service
5 rate order, shall not exceed an annual average 4% of the
6 utility's delivery base rate revenues, but shall not exceed
7 5.5% in any given year. On the effective date of new delivery
8 base rates, the surcharge shall be reduced to zero with
9 respect to qualifying infrastructure investment that is
10 transferred to the rate base used to establish the utility's
11 delivery base rates, provided that the utility may continue to
12 charge or refund any reconciliation adjustment determined
13 pursuant to subsection (e) of this Section.

14 (h) If a gas utility obtains a surcharge tariff under this
15 Section 9-220.3, then it and its affiliates are excused from
16 the rate case filing requirements contained in Sections
17 9-220(h) and 9-220(h-1). In the event a natural gas utility,
18 prior to the effective date of this amendatory Act of the 98th
19 General Assembly, made a rate case filing that is still
20 pending on the effective date of this amendatory Act of the
21 98th General Assembly, the natural gas utility may, at the
22 time it files its surcharge tariff with the Commission, also
23 file a notice with the Commission to withdraw its rate case
24 filing. Any affiliate of such natural gas utility may also
25 file to withdraw its rate case filing. Upon receipt of such
26 notice, the Commission shall dismiss the rate case filing with

1 prejudice and such tariffs and the record related thereto
2 shall not be the subject of any further hearing,
3 investigation, or proceeding of any kind related to rates for
4 gas delivery services. Notwithstanding the foregoing, a
5 natural gas utility shall not be permitted to withdraw a rate
6 case filing for which a proposed order recommending a rate
7 reduction is pending. A natural gas utility shall not be
8 permitted to withdraw the gas delivery services tariffs that
9 are the subject of Commission Docket Nos. 12-0511/12-0512
10 (cons.). None of the costs incurred for the withdrawn rate
11 case are recoverable from ratepayers.

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

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

25 (1) Baseline Distribution System Data: Information
26 such as demand, system pressures and flows, and metering

1 infrastructure.

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

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

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

8 (k) Within 45 days after filing, the Commission shall,
9 with reasonable notice, open an investigation to consider
10 whether the Plan meets the objectives set forth in this
11 subsection and contains the information required by subsection
12 (j). The Commission shall issue a final order approving the
13 Plan, with any modifications the Commission deems reasonable
14 and appropriate to achieve the goals of this Section, within
15 270 days after the Plan filing. The investigation shall assess
16 whether the DIMP:

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

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

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

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

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

5 (1) (j) This Section is repealed December 31, 2023.

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

7 (220 ILCS 5/9-227) (from Ch. 111 2/3, par. 9-227)

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

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

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

3 Sec. 10-104. Public hearings.

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

5 (1) rate cases;

6 (2) rulemakings;

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

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

11 (5) new programs;

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

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

17 (b) When the outcome of a major case would have effects
18 statewide, or have any significant effects outside the
19 territory of the utility or utilities involved in the case,
20 the Commission shall hold at least 5 public hearings for the
21 purpose of receiving public comment on each such major case.
22 One of these hearings must be in the Chicago metropolitan
23 area. One of these hearings must be in Springfield. The
24 remaining 3 hearings must be outside of the Chicago
25 metropolitan area and Springfield. One of the hearings shall

1 be held within the county in which the subject matter of the
2 hearing is situated, if it is situated within one county. When
3 the outcome of a major case would have effects only within the
4 territory of one utility, the Commission shall hold at least 5
5 public hearings at a variety of geographic locations within
6 the utility's territory. The locations shall be chosen to give
7 a wide variety of stakeholders the best opportunity to
8 participate in the hearings. The Commission may combine public
9 hearings for multiple major cases into one event at a single
10 venue, where practicable and compliant with all other
11 requirements.

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

26 (d) At least 3 commissioners shall attend each public

1 hearing in person.

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

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

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

23 (220 ILCS 5/16-105.17 new)

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

25 (a) Findings and Purpose. The General Assembly finds that

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

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

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

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

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

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

26 (5) The traditional regulatory model rewards utilities

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

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

26 (7) The General Assembly finds it would be beneficial

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

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

12 (b) Definitions. As used in this Section:

13 "Commission" means the Illinois Commerce Commission.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

26 (e) Plan Development Stakeholder Process. No later than

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

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

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

15 (ii) review utilities' historic and projected
16 load;

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

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

23 (v) integrate input from diverse stakeholders,
24 including representatives from environmental justice
25 communities, geographically diverse communities,
26 low-income representatives, consumer representatives,

1 environmental representatives, organized labor
2 representatives, third-party technology providers, and
3 utilities;

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

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

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

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

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

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

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

1 available by the Commission.

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

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

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

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

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

14 (f) Multi-Year Integrated Grid Plan.

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

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

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

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

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

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

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

25 (B) the distribution system annual loss
26 percentage for the prior year (average of 12

1 monthly loss percentages);

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

6 (D) total distribution substation capacity in
7 kVa;

8 (E) total distribution transformer capacity in
9 kVa;

10 (F) total miles of overhead distribution wire;

11 (G) total miles of underground distribution
12 wire;

13 (H) current and expected reliability measures;

14 (I) detailed listing of all high-voltage and
15 low-voltage substations and circuits including, at
16 minimum, the following for each substation and
17 circuit: age, remaining useful life, capacity
18 rating, historical peak demand, historical
19 interval data, historic annual peak load growth,
20 forecast future annual peak load growth,
21 historical outages and voltage violations,
22 distribution system reliability events,
23 anticipated or modeled violations, existing and
24 planned visibility and measurement (feeder-level
25 and time) data, monitoring and control
26 capabilities, daytime minimum load, and other

1 characteristics as necessary to allow the
2 Commission and stakeholders to analyze system data
3 for the purposes of achieving the goals of this
4 Section;

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

8 (K) total number and nameplate capacity of
9 distributed energy resources that completed
10 interconnection to the system in each of the prior
11 5 years, including average time to process
12 interconnection applications for each type of
13 resource and interconnection level.

14 (ii) Distribution System Planning Process. A
15 detailed description of the electric utility's
16 distribution system planning process including, but
17 not limited to: any process required by a regional
18 transmission organization; forecasts, inputs and
19 assumptions of future total load and future peak
20 demand; planned infrastructure investments and
21 underlying assumptions regarding the necessity of such
22 investments; and other relevant details for the
23 10-year planning horizon.

24 (iii) Hosting Capacity and Interconnection
25 Analysis. A hosting capacity analysis which includes a
26 detailed and current analysis of how much capacity is

1 available on each substation, circuit and node for
2 integrating renewable and distributed energy resources
3 as allowed by thermal ratings, protection system
4 limits, power quality standards, and safety standards.
5 This section must include: circuit-level maps and
6 downloadable data sets for public use; an assessment
7 of how anticipated investments (for as far into the
8 future as the utility has planned investments) will
9 impact the analysis; and a narrative discussion of how
10 the hosting capacity analysis advances customer-sited
11 distributed energy resources, including in particular
12 electric vehicles, electric storage systems and
13 photovoltaic resources.

14 (iv) Scenario Analysis and Load Forecasting.
15 Detailed load forecasts for the following 10 years at
16 the substation and circuit level, using dynamic load
17 forecasting (forecasting using multiple scenarios and
18 probabilistic planning) and accounting for the impacts
19 of anticipated energy efficiency programs, demand
20 response programs, distributed energy resources,
21 electric vehicle adoption, and other known or
22 anticipated variables. This section shall also include
23 a detailed description of the electric utility's
24 anticipated capacity, thermal, voltage or other grid
25 constraints for the following 3-year period, including
26 modifications or upgrades to the system required to

1 accommodate anticipated future load and distributed
2 energy resource adoption. This section shall also
3 include a discussion of the development of base-case,
4 medium and high scenarios of distributed energy
5 resource deployment, reflecting a reasonable mix of
6 individual distributed energy resource adoption and
7 aggregated or bundled distributed energy resource
8 service types, and detailed information on the
9 methodologies used to develop those scenarios.

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

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

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

20 (vii) Utility Operations Plan. A detailed
21 description of historic distribution system operations
22 and maintenance expenditures for the preceding 5 years
23 and of planned operations and maintenance expenditures
24 for the following 10 years, as well as the data,
25 reasoning and explanation supporting planned
26 expenditures. This section shall also include a

1 description of total costs spent on distributed energy
2 resource interconnection review and commissioning
3 (including application review, responding to
4 inquiries, metering, testing and other costs), as well
5 as interconnection fees and charges to customers and
6 installers of distributed energy resources, including
7 (application, metering and make-ready fees), broken
8 down by type of generation and category or level of
9 interconnection review, over each of the preceding 5
10 years.

11 (viii) Solution Sourcing Opportunities.

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

25 (ix) Interoperability Plan. A detailed description
26 of the utility's interoperability plan, which must

1 describe the manner in which the electric utility's
2 current and planned distribution system investments
3 will work together and exchange information and data,
4 the extent to which the utility is implementing open
5 standards and interfaces with third-party distributed
6 energy resource owners and aggregators, and the
7 utility's plan for interoperability testing and
8 certification.

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

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

1 and service quality data.

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

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

24 (i) time-of-use pricing program, pursuant to
25 Section 16-107.7 of this Act, hourly pricing program,
26 pursuant to Section 16-107 of this Act, and any other

1 time-variant or dynamic pricing program;

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

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

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

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

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

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

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

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

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

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

5 (A) meets the objectives of this Section;

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

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

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

17 (E) equitably benefits environmental justice
18 communities; and

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

21 (ii) The Commission, after notice and hearing,
22 shall modify each electric utility's Plan as necessary
23 to comply with the objectives of this Section. The
24 Commission may approve, or modify and approve, a Plan
25 only if it finds that the Plan is reasonable, complies
26 with the objectives and requirements of this Section,

1 and reasonably incorporates input from parties. The
2 Commission's approval of any Plan does not constitute
3 approval, or any adjudication of the prudence or
4 reasonableness, of any expenditures associated with
5 the Plan. The Commission may reject each electric
6 utility's Plan if it finds that the Plan does not
7 comply with the objectives and requirements of this
8 Section. Where the Commission enters an Order
9 rejecting a Plan, the utility must refile a Plan
10 within 3 months after that Order, and until the
11 Commission approves a Plan, the utility's existing
12 Plan will remain in effect.

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

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

24 (6) Implementation Plans.

25 (i) As part of its order approving a utility's
26 Multi-Year Integrated Grid Plan, including any

1 modifications required, the Commission shall create a
2 subsequent implementation plan docket, or multiple
3 implementation plan dockets, if the Commission
4 determines that multiple dockets would be preferable,
5 to consider the utility's detailed plans for:

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

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

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

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

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

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

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

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

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

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

22 (C) the marketing, customer recruitment and
23 engagement, financial incentive, procurement
24 approach and other important elements of the plan
25 or program, including efforts to cultivate
26 qualifying customers in low-income and

1 environmental justice communities;

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

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

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

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

25 (iii) The implementation plan dockets shall be
26 contested proceedings, with opportunities for

1 discovery and filing of testimony by interested
2 stakeholders. Each utility shall file its
3 implementation plans within 90 days after approval,
4 with any modifications, of its Multi-Year Integrated
5 Grid Plan.

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

16 (220 ILCS 5/16-107.7 new)

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

18 (a) The General Assembly finds that time-of-use rates and
19 pricing plans can lower energy costs for consumers and reduce
20 grid costs as well as help Illinois achieve its energy policy
21 goals by improving load shape, encouraging energy
22 conservation, and shifting usage away from periods where
23 fossil fuels are used to meet peak demand. Further, by
24 providing consumers information relating the costs of service
25 to the time of energy usage, time-of-use rates can help

1 consumers reduce their energy bills by using electricity when
2 it is less costly. Time-of-use rates can help allocate
3 electricity system costs more accurately and thus equitably to
4 those who cause costs. Such rates can reduce the need for
5 ramping resources and increase the grid's ability to
6 cost-effectively integrate greater quantities of variable
7 renewable energy and distributed energy resources.

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

20 (1) If more than one tariff is proposed, at least one
21 tariff shall include at least 3 time blocks: a peak time
22 block defined as 2 p.m. to 7 p.m. on nonholiday weekdays or
23 the 5 consecutive hours best reflecting the highest system
24 peak demands, an off-peak time block defined as 10 a.m. to
25 2 p.m. and 7 p.m. to 10 p.m. on nonholiday weekdays or the
26 7 total hours, occurring in some combination before and

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

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

10 (3) The time-of-use rate shall include the costs of
11 electric capacity, costs of transmission services, and
12 charges for network integration transmission service,
13 transmission enhancement, and locational reliability, as
14 these terms are defined in the PJM Interconnection LLC
15 Open Access Transmission Tariff and manuals on January 1,
16 2019, within the prices for each time block and seasonal
17 block in which the associated costs generally are
18 incurred. If the Open Access Transmission Tariff or
19 manuals subsequently renames those terms, the services
20 reflected under those terms shall continue to be included
21 in the time-of-use rate described in this paragraph (2).

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

1 monthly billing period and December monthly billing
2 period, respectively.

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

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

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

20 (d) If the Commission issues an order pursuant to this
21 subsection, the affected electric utility shall contract with
22 an entity not affiliated with the electric utility to serve as
23 a program administrator to develop and implement a program to
24 provide consumer outreach, enrollment, and education
25 concerning time-of-use pricing and to establish and administer
26 an information system and technical and other customer

1 assistance that is necessary to enable customers to manage
2 electricity use. The program administrator: (i) shall be
3 selected and compensated by the electric utility, subject to
4 Commission approval; (ii) shall have demonstrated technical
5 and managerial competence in the development and
6 administration of demand management programs; and (iii) may
7 develop and implement risk management, energy efficiency, and
8 other services related to energy use management for which the
9 program administrator shall be compensated by participants in
10 the program receiving such services. The electric utility
11 shall provide the program administrator with all information
12 and assistance necessary to perform the program
13 administrator's duties, including, but not limited to,
14 customer, account, and energy use data. The electric utility
15 shall permit the program administrator to include inserts in
16 residential customer bills 2 times per year to assist with
17 customer outreach and enrollment.

18 The program administrator shall submit an annual report to
19 the electric utility no later than April 1 of each year
20 describing the operation and results of the program, including
21 information concerning the number and types of customers using
22 the program, changes in customers' energy use patterns, an
23 assessment of the value of the program to both participants
24 and nonparticipants, and recommendations concerning
25 modification of the program and the tariff or tariffs filed
26 under this Section. This report shall be filed by the electric

1 utility with the Commission within 30 days after receipt and
2 shall be available to the public on the Commission's website.

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

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

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

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

22 (220 ILCS 5/16-108.18 new)

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

24 (a) Findings and Purpose. The General Assembly finds that
25 improving the alignment of utility customer and company

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

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

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

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

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

26 (4) The General Assembly therefore directs the

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

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

13 (b) Definitions.

14 As used in this Section:

15 "Commission" means the Illinois Commerce Commission.

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

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

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

1 not exceed 80% of area median income.

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

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

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

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

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

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

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

26 (5) incentivize utilities to undertake the most

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

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

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

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

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

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

23 (3) shared savings mechanisms;

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

26 (5) changes to the accounting treatment of capital and

1 operating expenditures; and

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

4 (e) Multi-Year Rate Plan.

5 (1) If an electric utility has a performance-based
6 formula rate in effect under Section 16-108.5 as of
7 December 31, 2020, then the utility shall file a petition
8 proposing tariffs implementing a 4-year Multi-Year Rate
9 Plan as provided in this Section no later than July 1, 2022
10 for delivery service rates to be effective from June 1,
11 2023 through May 31, 2027. The Commission shall issue an
12 order approving, approving as modified, or rejecting the
13 utility's plan no later than June 1, 2023. If the
14 Commission rejects the utility's plan, the deadline to
15 approve the plan or approve it as modified shall be
16 extended to 4 months from the date of the rejection. The
17 term "Multi-Year Rate Plan" refers to a plan establishing
18 the rates the utility may charge for each delivery year of
19 the 4-year period to be covered by the plan. The net
20 revenue requirement reflected in rates in effect on
21 December 31, 2021 for the electric utility shall remain in
22 effect until new rates are approved under the Multi-Year
23 Rate Plan, and no additional annual reconciliation under
24 Section 16-108.5 shall be made.

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

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

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

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

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

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

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

14 (ii) 530 basis points.

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

24 (D) For subsequent Multi-Year Rate Plans, the cost
25 of equity and capital structure shall be established
26 by the Commission and shall be set to reflect a

1 risk-adjusted return compared to the prevailing cost
2 of capital and comparable investments in the economy,
3 including U.S. Treasury rates, upon which additional
4 earning opportunities and penalties can be provided to
5 reflect utility performance against identified
6 outcomes.

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

10 (F) Amortize the amount of unprotected
11 property-related excess accumulated deferred income
12 taxes in rates as of December 31, 2022 over a period of
13 5 years.

14 (G) Disallow recovery of charitable contributions.

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

18 (I) Allow recovery of incentive compensation
19 expense that is based on the achievement of
20 operational metrics, including metrics related to
21 budget controls, outage duration and frequency,
22 safety, customer service, efficiency and productivity,
23 environmental compliance and attainment of
24 environmental goals, and other goals and metrics
25 approved by the Commission. Incentive compensation
26 expense that is based on net income or an affiliate's

1 earnings per share shall not be recoverable;

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

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

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

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

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

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

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

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

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

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

13 (f) Performance Incentive Mechanisms.

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

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

25 (B) Performance metrics, which will be used for
26 financially incentivizing improved utility

1 performance.

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

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

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

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

1 and service, and other factors.

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

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

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

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

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

26 (3) Metrics Requirements.

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

10 (B) Performance Metrics. Performance metrics shall
11 entail a description of the metric, a calculation
12 method, a data collection method, annual binding
13 performance targets, and monetary incentives (rewards
14 or penalties or both, depending on the metric) for
15 utilities' achievement of or failure to achieve their
16 performance targets. The Commission shall approve
17 performance metrics that (i) measure achievement of
18 the outcomes set forth in paragraph (2); (ii) are
19 supported by sufficient stakeholder input; (iii) have
20 one year of tracking data collected in a consistent
21 manner and verifiable by an independent evaluator in
22 order to establish a baseline; and (iv) require an
23 incentive (reward or penalty or both) to create
24 improved utility performance. While a single
25 performance metric may measure achievement of more
26 than one of the outcomes set forth in paragraph (2),

1 and such metrics should be valued, the Commission
2 shall not approve multiple performance metrics that
3 measure achievement identical or near-identical
4 results. Performance metrics should measure outcomes
5 and actual, rather than projected, results where
6 possible.

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

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

25 In determining the appropriate level of a reward
26 or penalty, the Commission shall consider: the extent

1 to which the amount is likely to encourage the utility
2 to achieve the performance target in the least cost
3 manner; the value of benefits to customers, the grid,
4 and the environment from achievement of the
5 performance target, including in particular benefits
6 to environmental justice and economically
7 disadvantaged communities; customer bill
8 affordability; the utility's revenue requirement; and
9 other such factors that the Commission deems
10 appropriate. The consideration of these factors shall
11 result in an incentive level that ensures benefits
12 exceed costs for customers.

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

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

26 (g) Initial Metrics. The Commission shall initiate a

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

16 Unless the tracking metrics in subparagraph (3) of
17 paragraph (A) and performance metrics in subparagraph (3) of
18 paragraph (B) of subsection (f) of this Section are found by
19 the Commission during initial metric-setting proceeding to not
20 meet the requirements set forth in this Section, the
21 Commission shall approve these metrics, and it shall establish
22 calculations and goals for the tracking metrics set forth in
23 subparagraph (3) of paragraph (A) of subsection (f) of this
24 Section and calculations, targets, and incentives for the
25 tracking metrics set forth in subparagraph (3) of paragraph
26 (B) of subsection (f) of this Section. If the Commission finds

1 that the metrics set forth in subparagraph (3) of paragraph
2 (A) and subparagraph (3) of paragraph (B) of subsection (f) of
3 this Section do not meet the requirements set forth in this
4 Section, then the Commission shall approve substitute metrics.
5 The Commission may also approve additional tracking and
6 performance metrics as appropriate if they meet the
7 requirements set forth in this Section.

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

- 10 (1) system Average Interruption Frequency Index;
11 (2) customer Average Interruption Duration Index; and
12 (3) peak load reductions enabled by demand response
13 programs.

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

19 The Commission shall also evaluate metrics that were
20 established in prior Annual Performance Evaluation proceedings
21 under the procedures set forth in subsection (i) to determine
22 if adjustments are required to improve the likelihood of the
23 outcomes described in paragraph (2) of subsection (f). For
24 metrics that were established in prior Annual Performance
25 Evaluation proceedings and that the Commission elects to
26 continue, the design of these metrics, including the goals of

1 tracking metrics and the targets and incentive levels and
2 structures of performance metrics, may be adjusted pursuant to
3 the requirements in this Section. The Commission may also
4 phase out tracking and performance metrics that were
5 established in prior Annual Performance Evaluation proceedings
6 if these metrics no longer meet the requirements of this
7 Section or if they are rendered obsolete by the changing needs
8 and technology of an evolving grid. Additionally, performance
9 metrics that no longer require an incentive to create improved
10 utility performance may become tracking metrics.

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

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

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

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

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

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

26 (D) the current-year goals for tracking metrics

1 and current-year targets for performance metrics;

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

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

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

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

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

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

20 The Commission shall consider the Report of the
21 independent evaluator in determining the utility's
22 achievement of performance targets. Discrepancies between
23 the utility's assumptions, baselines, targets, or
24 calculations and those of the independent evaluator shall
25 be closely scrutinized by the Commission. If the
26 Commission finds that the utility's reported data for any

1 metric or metrics significantly deviates from the data
2 reported by the independent evaluator, then the Commission
3 shall order the utility to revise its data collection and
4 calculation process within 60 days, with specifications
5 where appropriate.

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

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

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

1 INDEX

2 Statutes amended in order of appearance

3 New Act

4 5 ILCS 100/5-45.8 new

5 30 ILCS 105/5.935 new

6 220 ILCS 5/2-107 from Ch. 111 2/3, par. 2-107

7 220 ILCS 5/4-605 new

8 220 ILCS 5/9-220.3

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

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

11 220 ILCS 5/16-105.17 new

12 220 ILCS 5/16-107.7 new

13 220 ILCS 5/16-108.18 new