



98TH GENERAL ASSEMBLY

State of Illinois

2013 and 2014

SB1665

Introduced 2/13/2013, by Sen. David Koehler

SYNOPSIS AS INTRODUCED:

220 ILCS 5/9-220 from Ch. 111 2/3, par. 9-220
220 ILCS 5/9-244.5 new
220 ILCS 5/19-150.6 new

Amends the Public Utilities Act. Provides that certain gas natural utilities may recover expenditures made in relation to infrastructure modernization. Authorizes rates to be established on performance-based manner. Provides for customer assistance programs. Sets job creation and infrastructure modernization criteria. Authorizes recovery of delivery costs under a performance-based formula including incentive compensation expenses, pension expenses, and severance expenses. Provides for the deployment of advanced gas metering. Effective immediately.

LRB098 07846 JLS 40702 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 5. The Public Utilities Act is amended by changing
5 Section 9-220 and by adding Sections 9-244.5 and 19-150.6 as
6 follows:

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

8 Sec. 9-220. Rate changes based on changes in fuel costs.

9 (a) Notwithstanding the provisions of Section 9-201, the
10 Commission may authorize the increase or decrease of rates and
11 charges based upon changes in the cost of fuel used in the
12 generation or production of electric power, changes in the cost
13 of purchased power, or changes in the cost of purchased gas
14 through the application of fuel adjustment clauses or purchased
15 gas adjustment clauses. The Commission may also authorize the
16 increase or decrease of rates and charges based upon
17 expenditures or revenues resulting from the purchase or sale of
18 emission allowances created under the federal Clean Air Act
19 Amendments of 1990, through such fuel adjustment clauses, as a
20 cost of fuel. For the purposes of this paragraph, cost of fuel
21 used in the generation or production of electric power shall
22 include the amount of any fees paid by the utility for the
23 implementation and operation of a process for the

1 desulfurization of the flue gas when burning high sulfur coal
2 at any location within the State of Illinois irrespective of
3 the attainment status designation of such location; but shall
4 not include transportation costs of coal (i) except to the
5 extent that for contracts entered into on and after the
6 effective date of this amendatory Act of 1997, the cost of the
7 coal, including transportation costs, constitutes the lowest
8 cost for adequate and reliable fuel supply reasonably available
9 to the public utility in comparison to the cost, including
10 transportation costs, of other adequate and reliable sources of
11 fuel supply reasonably available to the public utility, or (ii)
12 except as otherwise provided in the next 3 sentences of this
13 paragraph. Such costs of fuel shall, when requested by a
14 utility or at the conclusion of the utility's next general
15 electric rate proceeding, whichever shall first occur, include
16 transportation costs of coal purchased under existing coal
17 purchase contracts. For purposes of this paragraph "existing
18 coal purchase contracts" means contracts for the purchase of
19 coal in effect on the effective date of this amendatory Act of
20 1991, as such contracts may thereafter be amended, but only to
21 the extent that any such amendment does not increase the
22 aggregate quantity of coal to be purchased under such contract.
23 Nothing herein shall authorize an electric utility to recover
24 through its fuel adjustment clause any amounts of
25 transportation costs of coal that were included in the revenue
26 requirement used to set base rates in its most recent general

1 rate proceeding. Cost shall be based upon uniformly applied
2 accounting principles. Annually, the Commission shall initiate
3 public hearings to determine whether the clauses reflect actual
4 costs of fuel, gas, power, or coal transportation purchased to
5 determine whether such purchases were prudent, and to reconcile
6 any amounts collected with the actual costs of fuel, power,
7 gas, or coal transportation prudently purchased. In each such
8 proceeding, the burden of proof shall be upon the utility to
9 establish the prudence of its cost of fuel, power, gas, or coal
10 transportation purchases and costs. The Commission shall issue
11 its final order in each such annual proceeding for an electric
12 utility by December 31 of the year immediately following the
13 year to which the proceeding pertains, provided, that the
14 Commission shall issue its final order with respect to such
15 annual proceeding for the years 1996 and earlier by December
16 31, 1998.

17 (b) A public utility providing electric service, other than
18 a public utility described in subsections (e) or (f) of this
19 Section, may at any time during the mandatory transition period
20 file with the Commission proposed tariff sheets that eliminate
21 the public utility's fuel adjustment clause and adjust the
22 public utility's base rate tariffs by the amount necessary for
23 the base fuel component of the base rates to recover the public
24 utility's average fuel and power supply costs per kilowatt-hour
25 for the 2 most recent years for which the Commission has issued
26 final orders in annual proceedings pursuant to subsection (a),

1 where the average fuel and power supply costs per kilowatt-hour
2 shall be calculated as the sum of the public utility's prudent
3 and allowable fuel and power supply costs as found by the
4 Commission in the 2 proceedings divided by the public utility's
5 actual jurisdictional kilowatt-hour sales for those 2 years.
6 Notwithstanding any contrary or inconsistent provisions in
7 Section 9-201 of this Act, in subsection (a) of this Section or
8 in any rules or regulations promulgated by the Commission
9 pursuant to subsection (g) of this Section, the Commission
10 shall review and shall by order approve, or approve as
11 modified, the proposed tariff sheets within 60 days after the
12 date of the public utility's filing. The Commission may modify
13 the public utility's proposed tariff sheets only to the extent
14 the Commission finds necessary to achieve conformance to the
15 requirements of this subsection (b). During the 5 years
16 following the date of the Commission's order, but in any event
17 no earlier than January 1, 2007, a public utility whose fuel
18 adjustment clause has been eliminated pursuant to this
19 subsection shall not file proposed tariff sheets seeking, or
20 otherwise petition the Commission for, reinstatement of a fuel
21 adjustment clause.

22 (c) Notwithstanding any contrary or inconsistent
23 provisions in Section 9-201 of this Act, in subsection (a) of
24 this Section or in any rules or regulations promulgated by the
25 Commission pursuant to subsection (g) of this Section, a public
26 utility providing electric service, other than a public utility

1 described in subsection (e) or (f) of this Section, may at any
2 time during the mandatory transition period file with the
3 Commission proposed tariff sheets that establish the rate per
4 kilowatt-hour to be applied pursuant to the public utility's
5 fuel adjustment clause at the average value for such rate
6 during the preceding 24 months, provided that such average rate
7 results in a credit to customers' bills, without making any
8 revisions to the public utility's base rate tariffs. The
9 proposed tariff sheets shall establish the fuel adjustment rate
10 for a specific time period of at least 3 years but not more
11 than 5 years, provided that the terms and conditions for any
12 reinstatement earlier than 5 years shall be set forth in the
13 proposed tariff sheets and subject to modification or approval
14 by the Commission. The Commission shall review and shall by
15 order approve the proposed tariff sheets if it finds that the
16 requirements of this subsection are met. The Commission shall
17 not conduct the annual hearings specified in the last 3
18 sentences of subsection (a) of this Section for the utility for
19 the period that the factor established pursuant to this
20 subsection is in effect.

21 (d) A public utility providing electric service, or a
22 public utility providing gas service may file with the
23 Commission proposed tariff sheets that eliminate the public
24 utility's fuel or purchased gas adjustment clause and adjust
25 the public utility's base rate tariffs to provide for recovery
26 of power supply costs or gas supply costs that would have been

1 recovered through such clause; provided, that the provisions of
2 this subsection (d) shall not be available to a public utility
3 described in subsections (e) or (f) of this Section to
4 eliminate its fuel adjustment clause. Notwithstanding any
5 contrary or inconsistent provisions in Section 9-201 of this
6 Act, in subsection (a) of this Section, or in any rules or
7 regulations promulgated by the Commission pursuant to
8 subsection (g) of this Section, the Commission shall review and
9 shall by order approve, or approve as modified in the
10 Commission's order, the proposed tariff sheets within 240 days
11 after the date of the public utility's filing. The Commission's
12 order shall approve rates and charges that the Commission,
13 based on information in the public utility's filing or on the
14 record if a hearing is held by the Commission, finds will
15 recover the reasonable, prudent and necessary jurisdictional
16 power supply costs or gas supply costs incurred or to be
17 incurred by the public utility during a 12 month period found
18 by the Commission to be appropriate for these purposes,
19 provided, that such period shall be either (i) a 12 month
20 historical period occurring during the 15 months ending on the
21 date of the public utility's filing, or (ii) a 12 month future
22 period ending no later than 15 months following the date of the
23 public utility's filing. The public utility shall include with
24 its tariff filing information showing both (1) its actual
25 jurisdictional power supply costs or gas supply costs for a 12
26 month historical period conforming to (i) above and (2) its

1 projected jurisdictional power supply costs or gas supply costs
2 for a future 12 month period conforming to (ii) above. If the
3 Commission's order requires modifications in the tariff sheets
4 filed by the public utility, the public utility shall have 7
5 days following the date of the order to notify the Commission
6 whether the public utility will implement the modified tariffs
7 or elect to continue its fuel or purchased gas adjustment
8 clause in force as though no order had been entered. The
9 Commission's order shall provide for any reconciliation of
10 power supply costs or gas supply costs, as the case may be, and
11 associated revenues through the date that the public utility's
12 fuel or purchased gas adjustment clause is eliminated. During
13 the 5 years following the date of the Commission's order, a
14 public utility whose fuel or purchased gas adjustment clause
15 has been eliminated pursuant to this subsection shall not file
16 proposed tariff sheets seeking, or otherwise petition the
17 Commission for, reinstatement or adoption of a fuel or
18 purchased gas adjustment clause. Nothing in this subsection (d)
19 shall be construed as limiting the Commission's authority to
20 eliminate a public utility's fuel adjustment clause or
21 purchased gas adjustment clause in accordance with any other
22 applicable provisions of this Act.

23 (e) Notwithstanding any contrary or inconsistent
24 provisions in Section 9-201 of this Act, in subsection (a) of
25 this Section, or in any rules promulgated by the Commission
26 pursuant to subsection (g) of this Section, a public utility

1 providing electric service to more than 1,000,000 customers in
2 this State may, within the first 6 months after the effective
3 date of this amendatory Act of 1997, file with the Commission
4 proposed tariff sheets that eliminate, effective January 1,
5 1997, the public utility's fuel adjustment clause without
6 adjusting its base rates, and such tariff sheets shall be
7 effective upon filing. To the extent the application of the
8 fuel adjustment clause had resulted in net charges to customers
9 after January 1, 1997, the utility shall also file a tariff
10 sheet that provides for a refund stated on a per kilowatt-hour
11 basis of such charges over a period not to exceed 6 months;
12 provided however, that such refund shall not include the
13 proportional amounts of taxes paid under the Use Tax Act,
14 Service Use Tax Act, Service Occupation Tax Act, and Retailers'
15 Occupation Tax Act on fuel used in generation. The Commission
16 shall issue an order within 45 days after the date of the
17 public utility's filing approving or approving as modified such
18 tariff sheet. If the fuel adjustment clause is eliminated
19 pursuant to this subsection, the Commission shall not conduct
20 the annual hearings specified in the last 3 sentences of
21 subsection (a) of this Section for the utility for any period
22 after December 31, 1996 and prior to any reinstatement of such
23 clause. A public utility whose fuel adjustment clause has been
24 eliminated pursuant to this subsection shall not file a
25 proposed tariff sheet seeking, or otherwise petition the
26 Commission for, reinstatement of the fuel adjustment clause

1 prior to January 1, 2007.

2 (f) Notwithstanding any contrary or inconsistent
3 provisions in Section 9-201 of this Act, in subsection (a) of
4 this Section, or in any rules or regulations promulgated by the
5 Commission pursuant to subsection (g) of this Section, a public
6 utility providing electric service to more than 500,000
7 customers but fewer than 1,000,000 customers in this State may,
8 within the first 6 months after the effective date of this
9 amendatory Act of 1997, file with the Commission proposed
10 tariff sheets that eliminate, effective January 1, 1997, the
11 public utility's fuel adjustment clause and adjust its base
12 rates by the amount necessary for the base fuel component of
13 the base rates to recover 91% of the public utility's average
14 fuel and power supply costs for the 2 most recent years for
15 which the Commission, as of January 1, 1997, has issued final
16 orders in annual proceedings pursuant to subsection (a), where
17 the average fuel and power supply costs per kilowatt-hour shall
18 be calculated as the sum of the public utility's prudent and
19 allowable fuel and power supply costs as found by the
20 Commission in the 2 proceedings divided by the public utility's
21 actual jurisdictional kilowatt-hour sales for those 2 years,
22 provided, that such tariff sheets shall be effective upon
23 filing. To the extent the application of the fuel adjustment
24 clause had resulted in net charges to customers after January
25 1, 1997, the utility shall also file a tariff sheet that
26 provides for a refund stated on a per kilowatt-hour basis of

1 such charges over a period not to exceed 6 months. Provided
2 however, that such refund shall not include the proportional
3 amounts of taxes paid under the Use Tax Act, Service Use Tax
4 Act, Service Occupation Tax Act, and Retailers' Occupation Tax
5 Act on fuel used in generation. The Commission shall issue an
6 order within 45 days after the date of the public utility's
7 filing approving or approving as modified such tariff sheet. If
8 the fuel adjustment clause is eliminated pursuant to this
9 subsection, the Commission shall not conduct the annual
10 hearings specified in the last 3 sentences of subsection (a) of
11 this Section for the utility for any period after December 31,
12 1996 and prior to any reinstatement of such clause. A public
13 utility whose fuel adjustment clause has been eliminated
14 pursuant to this subsection shall not file a proposed tariff
15 sheet seeking, or otherwise petition the Commission for,
16 reinstatement of the fuel adjustment clause prior to January 1,
17 2007.

18 (g) The Commission shall have authority to promulgate rules
19 and regulations to carry out the provisions of this Section.

20 (h) Any Illinois gas utility may enter into a contract on
21 or before September 30, 2011 for up to 10 years of supply with
22 any company for the purchase of substitute natural gas (SNG)
23 produced from coal through the gasification process if the
24 company has commenced construction of a clean coal SNG facility
25 by July 1, 2012 and commencement of construction shall mean
26 that material physical site work has occurred, such as site

1 clearing and excavation, water runoff prevention, water
2 retention reservoir preparation, or foundation development.
3 The contract shall contain the following provisions: (i) at
4 least 90% of feedstock to be used in the gasification process
5 shall be coal with a high volatile bituminous rank and greater
6 than 1.7 pounds of sulfur per million Btu content; (ii) at the
7 time the contract term commences, the price per million Btu may
8 not exceed \$7.95 in 2008 dollars, adjusted annually based on
9 the change in the Annual Consumer Price Index for All Urban
10 Consumers for the Midwest Region as published in April by the
11 United States Department of Labor, Bureau of Labor Statistics
12 (or a suitable Consumer Price Index calculation if this
13 Consumer Price Index is not available) for the previous
14 calendar year; provided that the price per million Btu shall
15 not exceed \$9.95 at any time during the contract; (iii) the
16 utility's supply contract for the purchase of SNG does not
17 exceed 15% of the annual system supply requirements of the
18 utility as of 2008; and (iv) the contract costs pursuant to
19 subsection (h-10) of this Section shall not include any
20 lobbying expenses, charitable contributions, advertising,
21 organizational memberships, carbon dioxide pipeline or
22 sequestration expenses, or marketing expenses.

23 Any gas utility that is providing service to more than
24 150,000 customers on August 2, 2011 (the effective date of
25 Public Act 97-239) shall either elect to enter into a contract
26 on or before September 30, 2011 for 10 years of SNG supply with

1 the owner of a clean coal SNG facility or to file biennial rate
2 proceedings before the Commission in the years 2012, 2014, and
3 2016, with such filings made after August 2, 2011 and no later
4 than September 30 of the years 2012, 2014, and 2016 consistent
5 with all requirements of 83 Ill. Adm. Code 255 and 285 as
6 though the gas utility were filing for an increase in its
7 rates, without regard to whether such filing would produce an
8 increase, a decrease, or no change in the gas utility's rates,
9 and the Commission shall review the gas utility's filing and
10 shall issue its order in accordance with the provisions of
11 Section 9-201 of this Act; provided, however, that a gas
12 utility having performance-based rates in effect pursuant to
13 Section 9-244.5 of this Act that previously elected to make
14 rate filings under this Section shall have no obligation to
15 make such filings while such performance-based rates are in
16 effect and the gas utility may withdraw, and the Commission
17 shall approve any such request to withdraw, any pending rate
18 filing at any time after it files to implement
19 performance-based rates pursuant to Section 9-244.5.

20 Within 7 days after August 2, 2011, the owner of the clean
21 coal SNG facility shall submit to the Illinois Power Agency and
22 each gas utility that is providing service to more than 150,000
23 customers on August 2, 2011 a copy of a draft contract. Within
24 30 days after the receipt of the draft contract, each such gas
25 utility shall provide the Illinois Power Agency and the owner
26 of the clean coal SNG facility with its comments and

1 recommended revisions to the draft contract. Within 7 days
2 after the receipt of the gas utility's comments and recommended
3 revisions, the owner of the facility shall submit its
4 responsive comments and a further revised draft of the contract
5 to the Illinois Power Agency. The Illinois Power Agency shall
6 review the draft contract and comments.

7 During its review of the draft contract, the Illinois Power
8 Agency shall:

9 (1) review and confirm in writing that the terms stated
10 in this subsection (h) are incorporated in the SNG
11 contract;

12 (2) review the SNG pricing formula included in the
13 contract and approve that formula if the Illinois Power
14 Agency determines that the formula, at the time the
15 contract term commences: (A) starts with a price of \$6.50
16 per MMBtu adjusted by the adjusted final capitalized plant
17 cost; (B) takes into account budgeted miscellaneous net
18 revenue after cost allowance, including sale of SNG
19 produced by the clean coal SNG facility above the nameplate
20 capacity of the facility and other by-products produced by
21 the facility, as approved by the Illinois Power Agency; (C)
22 does not include carbon dioxide transportation or
23 sequestration expenses; and (D) includes all provisions
24 required under this subsection (h); if the Illinois Power
25 Agency does not approve of the SNG pricing formula, then
26 the Illinois Power Agency shall modify the formula to

1 ensure that it meets the requirements of this subsection
2 (h);

3 (3) review and approve the amount of budgeted
4 miscellaneous net revenue after cost allowance, including
5 sale of SNG produced by the clean coal SNG facility above
6 the nameplate capacity of the facility and other
7 by-products produced by the facility, to be included in the
8 pricing formula; the Illinois Power Agency shall approve
9 the amount of budgeted miscellaneous net revenue to be
10 included in the pricing formula if it determines the
11 budgeted amount to be reasonable and accurate;

12 (4) review and confirm in writing that using the EIA
13 Annual Energy Outlook-2011 Henry Hub Spot Price, the
14 contract terms set out in subsection (h), the
15 reconciliation account terms as set out in subsection
16 (h-15), and an estimated inflation rate of 2.5% for each
17 corresponding year, that there will be no cumulative
18 estimated increase for residential customers; and

19 (5) allocate the nameplate capacity of the clean coal
20 SNG by total therms sold to ultimate customers by each gas
21 utility in 2008; provided, however, no utility shall be
22 required to purchase more than 42% of the projected annual
23 output of the facility; additionally, the Illinois Power
24 Agency shall further adjust the allocation only as required
25 to take into account (A) adverse consolidation,
26 derivative, or lease impacts to the balance sheet or income

1 statement of any gas utility or (B) the physical capacity
2 of the gas utility to accept SNG.

3 If the parties to the contract do not agree on the terms
4 therein, then the Illinois Power Agency shall retain an
5 independent mediator to mediate the dispute between the
6 parties. If the parties are in agreement on the terms of the
7 contract, then the Illinois Power Agency shall approve the
8 contract. If after mediation the parties have failed to come to
9 agreement, then the Illinois Power Agency shall revise the
10 draft contract as necessary to confirm that the contract
11 contains only terms that are reasonable and equitable. The
12 Illinois Power Agency may, in its discretion, retain an
13 independent, qualified, and experienced expert to assist in its
14 obligations under this subsection (h). The Illinois Power
15 Agency shall adopt and make public policies detailing the
16 processes for retaining a mediator and an expert under this
17 subsection (h). Any mediator or expert retained under this
18 subsection (h) shall be retained no later than 60 days after
19 August 2, 2011.

20 The Illinois Power Agency shall complete all of its
21 responsibilities under this subsection (h) within 60 days after
22 August 2, 2011. The clean coal SNG facility shall pay a
23 reasonable fee as required by the Illinois Power Agency for its
24 services under this subsection (h) and shall pay the mediator's
25 and expert's reasonable fees, if any. A gas utility and its
26 customers shall have no obligation to reimburse the clean coal

1 SNG facility or the Illinois Power Agency of any such costs.

2 Within 30 days after commercial production of SNG has
3 begun, the Commission shall initiate a review to determine
4 whether the final capitalized plant cost of the clean coal SNG
5 facility reflects actual incurred costs and whether the
6 incurred costs were reasonable. In determining the actual
7 incurred costs included in the final capitalized plant cost and
8 the reasonableness of those costs, the Commission may in its
9 discretion retain independent, qualified, and experienced
10 experts to assist in its determination. The expert shall not
11 own or control any direct or indirect interest in the clean
12 coal SNG facility and shall have no contractual relationship
13 with the clean coal SNG facility. If an expert is retained by
14 the Commission, then the clean coal SNG facility shall pay the
15 expert's reasonable fees. The fees shall not be passed on to a
16 utility or its customers. The Commission shall adopt and make
17 public a policy detailing the process for retaining experts
18 under this subsection (h).

19 Within 30 days after completion of its review, the
20 Commission shall initiate a formal proceeding on the final
21 capitalized plant cost of the clean coal SNG facility at which
22 comments and testimony may be submitted by any interested
23 parties and the public. If the Commission finds that the final
24 capitalized plant cost includes costs that were not actually
25 incurred or costs that were unreasonably incurred, then the
26 Commission shall disallow the amount of non-incurred or

1 unreasonable costs from the SNG price under contracts entered
2 into under this subsection (h). If the Commission disallows any
3 costs, then the Commission shall adjust the SNG price using the
4 price formula in the contract approved by the Illinois Power
5 Agency under this subsection (h) to reflect the disallowed
6 costs and shall enter an order specifying the revised price. In
7 addition, the Commission's order shall direct the clean coal
8 SNG facility to issue refunds of such sums as shall represent
9 the difference between actual gross revenues and the gross
10 revenue that would have been obtained based upon the same
11 volume, from the price revised by the Commission. Any refund
12 shall include interest calculated at a rate determined by the
13 Commission and shall be returned according to procedures
14 prescribed by the Commission.

15 Nothing in this subsection (h) shall preclude any party
16 affected by a decision of the Commission under this subsection
17 (h) from seeking judicial review of the Commission's decision.

18 (h-1) Any Illinois gas utility may enter into a sourcing
19 agreement for up to 30 years of supply with the clean coal SNG
20 brownfield facility if the clean coal SNG brownfield facility
21 has commenced construction. Any gas utility that is providing
22 service to more than 150,000 customers on July 13, 2011 (the
23 effective date of Public Act 97-096) shall either elect to file
24 biennial rate proceedings before the Commission in the years
25 2012, 2014, and 2016 or enter into a sourcing agreement or
26 sourcing agreements with a clean coal SNG brownfield facility

1 with an initial term of 30 years for either (i) a percentage of
2 43,500,000,000 cubic feet per year, such that the utilities
3 entering into sourcing agreements with the clean coal SNG
4 brownfield facility purchase 100%, allocated by total therms
5 sold to ultimate customers by each gas utility in 2008 or (ii)
6 such lesser amount as may be available from the clean coal SNG
7 brownfield facility; provided that no utility shall be required
8 to purchase more than 42% of the projected annual output of the
9 clean coal SNG brownfield facility, with the remainder of such
10 utility's obligation to be divided proportionately between the
11 other utilities, and provided that the Illinois Power Agency
12 shall further adjust the allocation only as required to take
13 into account adverse consolidation, derivative, or lease
14 impacts to the balance sheet or income statement of any gas
15 utility.

16 A gas utility electing to file biennial rate proceedings
17 before the Commission must file a notice of its election with
18 the Commission within 60 days after July 13, 2011 or its right
19 to make the election is irrevocably waived. A gas utility
20 electing to file biennial rate proceedings shall make such
21 filings no later than August 1 of the years 2012, 2014, and
22 2016, consistent with all requirements of 83 Ill. Adm. Code 255
23 and 285 as though the gas utility were filing for an increase
24 in its rates, without regard to whether such filing would
25 produce an increase, a decrease, or no change in the gas
26 utility's rates, and notwithstanding any other provisions of

1 this Act, the Commission shall fully review the gas utility's
2 filing and shall issue its order in accordance with the
3 provisions of Section 9-201 of this Act, provided, however,
4 that a gas utility having performance-based rates in effect
5 pursuant to Section 9-244.5 of this Act that previously elected
6 to make rate filings under this Section shall have no
7 obligation to make such filings while such performance-based
8 rates are in effect and the gas utility may withdraw, and the
9 Commission shall approve any such request to withdraw, any
10 pending rate filing at any time after it files to implement
11 performance-based rates pursuant to Section 9-244.5 regardless
12 ~~of whether the Commission has approved a formula rate for the~~
13 ~~gas utility.~~

14 Within 15 days after July 13, 2011, the owner of the clean
15 coal SNG brownfield facility shall submit to the Illinois Power
16 Agency and each gas utility that is providing service to more
17 than 150,000 customers on July 13, 2011 a copy of a draft
18 sourcing agreement. Within 45 days after receipt of the draft
19 sourcing agreement, each such gas utility shall provide the
20 Illinois Power Agency and the owner of a clean coal SNG
21 brownfield facility with its comments and recommended
22 revisions to the draft sourcing agreement. Within 15 days after
23 the receipt of the gas utility's comments and recommended
24 revisions, the owner of the clean coal SNG brownfield facility
25 shall submit its responsive comments and a further revised
26 draft of the sourcing agreement to the Illinois Power Agency.

1 The Illinois Power Agency shall review the draft sourcing
2 agreement and comments.

3 If the parties to the sourcing agreement do not agree on
4 the terms therein, then the Illinois Power Agency shall retain
5 an independent mediator to mediate the dispute between the
6 parties. If the parties are in agreement on the terms of the
7 sourcing agreement, the Illinois Power Agency shall approve the
8 final draft sourcing agreement. If after mediation the parties
9 have failed to come to agreement, then the Illinois Power
10 Agency shall revise the draft sourcing agreement as necessary
11 to confirm that the final draft sourcing agreement contains
12 only terms that are reasonable and equitable. The Illinois
13 Power Agency shall adopt and make public a policy detailing the
14 process for retaining a mediator under this subsection (h-1).
15 Any mediator retained to assist with mediating disputes between
16 the parties regarding the sourcing agreement shall be retained
17 no later than 60 days after July 13, 2011.

18 Upon approval of a final draft agreement, the Illinois
19 Power Agency shall submit the final draft agreement to the
20 Capital Development Board and the Commission no later than 90
21 days after July 13, 2011. The gas utility and the clean coal
22 SNG brownfield facility shall pay a reasonable fee as required
23 by the Illinois Power Agency for its services under this
24 subsection (h-1) and shall pay the mediator's reasonable fees,
25 if any. The Illinois Power Agency shall adopt and make public a
26 policy detailing the process for retaining a mediator under

1 this Section.

2 The sourcing agreement between a gas utility and the clean
3 coal SNG brownfield facility shall contain the following
4 provisions:

5 (1) Any and all coal used in the gasification process
6 must be coal that has high volatile bituminous rank and
7 greater than 1.7 pounds of sulfur per million Btu content.

8 (2) Coal and petroleum coke are feedstocks for the
9 gasification process, with coal comprising at least 50% of
10 the total feedstock over the term of the sourcing agreement
11 unless the facility reasonably determines that it is
12 necessary to use additional petroleum coke to deliver net
13 consumer savings, in which case the facility shall use coal
14 for at least 35% of the total feedstock over the term of
15 any sourcing agreement and with the feedstocks to be
16 procured in accordance with requirements of Section 1-78 of
17 the Illinois Power Agency Act.

18 (3) The sourcing agreement has an initial term that
19 once entered into terminates no more than 30 years after
20 the commencement of the commercial production of SNG at the
21 clean coal SNG brownfield facility.

22 (4) The clean coal SNG brownfield facility guarantees a
23 minimum of \$100,000,000 in consumer savings to customers of
24 the utilities that have entered into sourcing agreements
25 with the clean coal SNG brownfield facility, calculated in
26 real 2010 dollars at the conclusion of the term of the

1 sourcing agreement by comparing the delivered SNG price to
2 the Chicago City-gate price on a weighted daily basis for
3 each day over the entire term of the sourcing agreement, to
4 be provided in accordance with subsection (h-2) of this
5 Section.

6 (5) Prior to the clean coal SNG brownfield facility
7 issuing a notice to proceed to construction, the clean coal
8 SNG brownfield facility shall establish a consumer
9 protection reserve account for the benefit of the customers
10 of the utilities that have entered into sourcing agreements
11 with the clean coal SNG brownfield facility pursuant to
12 this subsection (h-1), with cash principal in the amount of
13 \$150,000,000. This cash principal shall only be
14 recoverable through the consumer protection reserve
15 account and not as a cost to be recovered in the delivered
16 SNG price pursuant to subsection (h-3) of this Section. The
17 consumer protection reserve account shall be maintained
18 and administered by an independent trustee that is mutually
19 agreed upon by the clean coal SNG brownfield facility, the
20 utilities, and the Commission in an interest-bearing
21 account in accordance with subsection (h-2) of this
22 Section.

23 "Consumer protection reserve account principal maximum
24 amount" shall mean the maximum amount of principal to be
25 maintained in the consumer protection reserve account.
26 During the first 2 years of operation of the facility,

1 there shall be no consumer protection reserve account
2 maximum amount. After the first 2 years of operation of the
3 facility, the consumer protection reserve account maximum
4 amount shall be \$150,000,000. After 5 years of operation,
5 and every 5 years thereafter, the trustee shall calculate
6 the 5-year average balance of the consumer protection
7 reserve account. If the trustee determines that during the
8 prior 5 years the consumer protection reserve account has
9 had an average account balance of less than \$75,000,000,
10 then the consumer protection reserve account principal
11 maximum amount shall be increased by \$5,000,000. If the
12 trustee determines that during the prior 5 years the
13 consumer protection reserve account has had an average
14 account balance of more than \$75,000,000, then the consumer
15 protection reserve account principal maximum amount shall
16 be decreased by \$5,000,000.

17 (6) The clean coal SNG brownfield facility shall
18 identify and sell economically viable by-products produced
19 by the facility.

20 (7) Fifty percent of all additional net revenue,
21 defined as miscellaneous net revenue from products
22 produced by the facility and delivered during the month
23 after cost allowance for costs associated with additional
24 net revenue that are not otherwise recoverable pursuant to
25 subsection (h-3) of this Section, including net revenue
26 from sales of substitute natural gas derived from the

1 facility above the nameplate capacity of the facility and
2 other by-products produced by the facility, shall be
3 credited to the consumer protection reserve account
4 pursuant to subsection (h-2) of this Section.

5 (8) The delivered SNG price per million btu to be paid
6 monthly by the utility to the clean coal SNG brownfield
7 facility, which shall be based only upon the following: (A)
8 a capital recovery charge, operations and maintenance
9 costs, and sequestration costs, only to the extent approved
10 by the Commission pursuant to paragraphs (1), (2), and (3)
11 of subsection (h-3) of this Section; (B) the actual
12 delivered and processed fuel costs pursuant to paragraph
13 (4) of subsection (h-3) of this Section; (C) actual costs
14 of SNG transportation pursuant to paragraph (6) of
15 subsection (h-3) of this Section; (D) certain taxes and
16 fees imposed by the federal government, the State, or any
17 unit of local government as provided in paragraph (6) of
18 subsection (h-3) of this Section; and (E) the credit, if
19 any, from the consumer protection reserve account pursuant
20 to subsection (h-2) of this Section. The delivered SNG
21 price per million Btu shall proportionately reflect these
22 elements over the term of the sourcing agreement.

23 (9) A formula to translate the recoverable costs and
24 charges under subsection (h-3) of this Section into the
25 delivered SNG price per million btu.

26 (10) Title to the SNG shall pass at a mutually

1 agreeable point in Illinois, and may provide that, rather
2 than the utility taking title to the SNG, a mutually agreed
3 upon third-party gas marketer pursuant to a contract
4 approved by the Illinois Power Agency or its designee may
5 take title to the SNG pursuant to an agreement between the
6 utility, the owner of the clean coal SNG brownfield
7 facility, and the third-party gas marketer.

8 (11) A utility may exit the sourcing agreement without
9 penalty if the clean coal SNG brownfield facility does not
10 commence construction by July 1, 2015.

11 (12) A utility is responsible to pay only the
12 Commission determined unit price cost of SNG that is
13 purchased by the utility. Nothing in the sourcing agreement
14 will obligate a utility to invest capital in a clean coal
15 SNG brownfield facility.

16 (13) The quality of SNG must, at a minimum, be
17 equivalent to the quality required for interstate pipeline
18 gas before a utility is required to accept and pay for SNG
19 gas.

20 (14) Nothing in the sourcing agreement will require a
21 utility to construct any facilities to accept delivery of
22 SNG. Provided, however, if a utility is required by law or
23 otherwise elects to connect the clean coal SNG brownfield
24 facility to an interstate pipeline, then the utility shall
25 be entitled to recover pursuant to its tariffs all just and
26 reasonable costs that are prudently incurred. Any costs

1 incurred by the utility to receive, deliver, manage, or
2 otherwise accommodate purchases under the SNG sourcing
3 agreement will be fully recoverable through a utility's
4 purchased gas adjustment clause rider mechanism in
5 conjunction with a SNG brownfield facility rider
6 mechanism. The SNG brownfield facility rider mechanism (A)
7 shall be applicable to all customers who receive
8 transportation service from the utility, (B) shall be
9 designed to have an equal percent impact on the
10 transportation services rates of each class of the
11 utility's customers, and (C) shall accurately reflect the
12 net consumer savings, if any, and above-market costs, if
13 any, associated with the utility receiving, delivering,
14 managing, or otherwise accommodating purchases under the
15 SNG sourcing agreement.

16 (15) Remedies for the clean coal SNG brownfield
17 facility's failure to deliver a designated amount for a
18 designated period.

19 (16) The clean coal SNG brownfield facility shall make
20 a good faith effort to ensure that an amount equal to not
21 less than 15% of the value of its prime construction
22 contract for the facility shall be established as a goal to
23 be awarded to minority owned businesses, female owned
24 businesses, and businesses owned by a person with a
25 disability; provided that at least 75% of the amount of
26 such total goal shall be for minority owned businesses.

1 "Minority owned business", "female owned business", and
2 "business owned by a person with a disability" shall have
3 the meanings ascribed to them in Section 2 of the Business
4 Enterprise for Minorities, Females and Persons with
5 Disabilities Act.

6 (17) Prior to the clean coal SNG brownfield facility
7 issuing a notice to proceed to construction, the clean coal
8 SNG brownfield facility shall file with the Commission a
9 certificate from an independent engineer that the clean
10 coal SNG brownfield facility has (A) obtained all
11 applicable State and federal environmental permits
12 required for construction; (B) obtained approval from the
13 Commission of a carbon capture and sequestration plan; and
14 (C) obtained all necessary permits required for
15 construction for the transportation and sequestration of
16 carbon dioxide as set forth in the Commission-approved
17 carbon capture and sequestration plan.

18 (h-2) Consumer protection reserve account. The clean coal
19 SNG brownfield facility shall guarantee a minimum of
20 \$100,000,000 in consumer savings to customers of the utilities
21 that have entered into sourcing agreements with the clean coal
22 SNG brownfield facility, calculated in real 2010 dollars at the
23 conclusion of the term of the sourcing agreement by comparing
24 the delivered SNG price to the Chicago City-gate price on a
25 weighted daily basis for each day over the entire term of the
26 sourcing agreement. Prior to the clean coal SNG brownfield

1 facility issuing a notice to proceed to construction, the clean
2 coal SNG brownfield facility shall establish a consumer
3 protection reserve account for the benefit of the retail
4 customers of the utilities that have entered into sourcing
5 agreements with the clean coal SNG brownfield facility pursuant
6 to subsection (h-1), with cash principal in the amount of
7 \$150,000,000. Such cash principal shall only be recovered
8 through the consumer protection reserve account and not as a
9 cost to be recovered in the delivered SNG price pursuant to
10 subsection (h-3) of this Section. The consumer protection
11 reserve account shall be maintained and administered by an
12 independent trustee that is mutually agreed upon by the clean
13 coal SNG brownfield facility, the utilities, and the Commission
14 in an interest-bearing account in accordance with the
15 following:

16 (1) The clean coal SNG brownfield facility monthly
17 shall calculate (A) the difference between the monthly
18 delivered SNG price and the Chicago City-gate price, by
19 comparing the delivered SNG price, which shall include the
20 cost of transportation to the delivery point, if any, to
21 the Chicago City-gate price on a weighted daily basis for
22 each day of the prior month based upon a mutually agreed
23 upon published index and (B) the overage amount, if any, by
24 calculating the annualized incremental additional cost, if
25 any, of the delivered SNG in excess of 2.015% of the
26 average annual inflation-adjusted amounts paid by all gas

1 distribution customers in connection with natural gas
2 service during the 5 years ending May 31, 2010.

3 (2) During the first 2 years of operation of the
4 facility:

5 (A) to the extent there is an overage amount, the
6 consumer protection reserve account shall be used to
7 provide a credit to reduce the SNG price by an amount
8 equal to the overage amount; and

9 (B) to the extent the monthly delivered SNG price
10 is less than or equal to the Chicago City-gate price,
11 the utility shall credit the difference between the
12 monthly delivered SNG price and the monthly Chicago
13 City-gate price, if any, to the consumer protection
14 reserve account. Such credit issued pursuant to this
15 paragraph (B) shall be deemed prudent and reasonable
16 and not subject to a Commission prudence review;

17 (3) After 2 years of operation of the facility, and
18 monthly, on an on-going basis, thereafter:

19 (A) to the extent that the monthly delivered SNG
20 price is less than or equal to the Chicago City-gate
21 price, calculated using the weighted average of the
22 daily Chicago City-gate price on a daily basis over the
23 entire month, the utility shall credit the difference,
24 if any, to the consumer protection reserve account.
25 Such credit issued pursuant to this subparagraph (A)
26 shall be deemed prudent and reasonable and not subject

1 to a Commission prudence review;

2 (B) any amounts in the consumer protection reserve
3 account in excess of the consumer protection reserve
4 account principal maximum amount shall be distributed
5 as follows: (i) if retail customers have not realized
6 net consumer savings, calculated by comparing the
7 delivered SNG price to the weighted average of the
8 daily Chicago City-gate price on a daily basis over the
9 entire term of the sourcing agreement to date, then 50%
10 of any amounts in the consumer protection reserve
11 account in excess of the consumer protection reserve
12 account principal maximum shall be distributed to the
13 clean coal SNG brownfield facility, with the remaining
14 50% of any such additional amounts being credited to
15 retail customers, and (ii) if retail customers have
16 realized net consumer savings, then 100% of any amounts
17 in the consumer protection reserve account in excess of
18 the consumer protection reserve account principal
19 maximum shall be distributed to the clean coal SNG
20 brownfield facility; provided, however, that under no
21 circumstances shall the total cumulative amount
22 distributed to the clean coal SNG brownfield facility
23 under this subparagraph (B) exceed \$150,000,000;

24 (C) to the extent there is an overage amount, after
25 distributing the amounts pursuant to subparagraph (B)
26 of this paragraph (3), if any, the consumer protection

1 reserve account shall be used to provide a credit to
2 reduce the SNG price by an amount equal to the overage
3 amount;

4 (D) if retail customers have realized net consumer
5 savings, calculated by comparing the delivered SNG
6 price to the weighted average of the daily Chicago
7 City-gate price on a daily basis over the entire term
8 of the sourcing agreement to date, then after
9 distributing the amounts pursuant to subparagraphs (B)
10 and (C) of this paragraph (3), 50% of any additional
11 amounts in the consumer protection reserve account in
12 excess of the consumer protection reserve account
13 principal maximum shall be distributed to the clean
14 coal SNG brownfield facility, with the remaining 50% of
15 any such additional amounts being credited to retail
16 customers; provided, however, that if retail customers
17 have not realized such net consumer savings, no such
18 distribution shall be made to the clean coal SNG
19 brownfield facility, and 100% of such additional
20 amounts shall be credited to the retail customers to
21 the extent the consumer protection reserve account
22 exceeds the consumer protection reserve account
23 principal maximum amount.

24 (4) Fifty percent of all additional net revenue,
25 defined as miscellaneous net revenue after cost allowance
26 for costs associated with additional net revenue that are

1 not otherwise recoverable pursuant to subsection (h-3) of
2 this Section, including net revenue from sales of
3 substitute natural gas derived from the facility above the
4 nameplate capacity of the facility and other by-products
5 produced by the facility, shall be credited to the consumer
6 protection reserve account.

7 (5) At the conclusion of the term of the sourcing
8 agreement, to the extent retail customers have not saved
9 the minimum of \$100,000,000 in consumer savings as
10 guaranteed in this subsection (h-2), amounts in the
11 consumer protection reserve account shall be credited to
12 retail customers to the extent the retail customers have
13 saved the minimum of \$100,000,000; 50% of any additional
14 amounts in the consumer protection reserve account shall be
15 distributed to the company, and the remaining 50% shall be
16 distributed to retail customers.

17 (6) If, at the conclusion of the term of the sourcing
18 agreement, the customers have not saved the minimum
19 \$100,000,000 in savings as guaranteed in this subsection
20 (h-2) and the consumer protection reserve account has been
21 depleted, then the clean coal SNG brownfield facility shall
22 be liable for any remaining amount owed to the retail
23 customers to the extent that the customers are provided
24 with the \$100,000,000 in savings as guaranteed in this
25 subsection (h-2). The retail customers shall have first
26 priority in recovering that debt above any creditors,

1 except the original senior secured lender to the extent
2 that the original senior secured lender has any senior
3 secured debt outstanding, including any clean coal SNG
4 brownfield facility parent companies or affiliates.

5 (7) The clean coal SNG brownfield facility, the
6 utilities, and the trustee shall work together to take
7 commercially reasonable steps to minimize the tax impact of
8 these transactions, while preserving the consumer
9 benefits.

10 (8) The clean coal SNG brownfield facility shall each
11 month, starting in the facility's first year of commercial
12 operation, file with the Commission, in such form as the
13 Commission shall require, a report as to the consumer
14 protection reserve account. The monthly report must
15 contain the following information:

16 (A) the extent the monthly delivered SNG price is
17 greater than, less than, or equal to the Chicago
18 City-gate price;

19 (B) the amount credited or debited to the consumer
20 protection reserve account during the month;

21 (C) the amounts credited to consumers and
22 distributed to the clean coal SNG brownfield facility
23 during the month;

24 (D) the total amount of the consumer protection
25 reserve account at the beginning and end of the month;

26 (E) the total amount of consumer savings to date;

1 (F) a confidential summary of the inputs used to
2 calculate the additional net revenue; and

3 (G) any other additional information the
4 Commission shall require.

5 When any report is erroneous or defective or appears to
6 the Commission to be erroneous or defective, the Commission
7 may notify the clean coal SNG brownfield facility to amend
8 the report within 30 days, and, before or after the
9 termination of the 30-day period, the Commission may
10 examine the trustee of the consumer protection reserve
11 account or the officers, agents, employees, books,
12 records, or accounts of the clean coal SNG brownfield
13 facility and correct such items in the report as upon such
14 examination the Commission may find defective or
15 erroneous. All reports shall be under oath.

16 All reports made to the Commission by the clean coal
17 SNG brownfield facility and the contents of the reports
18 shall be open to public inspection and shall be deemed a
19 public record under the Freedom of Information Act. Such
20 reports shall be preserved in the office of the Commission.
21 The Commission shall publish an annual summary of the
22 reports prior to February 1 of the following year. The
23 annual summary shall be made available to the public on the
24 Commission's website and shall be submitted to the General
25 Assembly.

26 Any facility that fails to file a report required under

1 this paragraph (8) to the Commission within the time
2 specified or to make specific answer to any question
3 propounded by the Commission within 30 days from the time
4 it is lawfully required to do so, or within such further
5 time not to exceed 90 days as may in its discretion be
6 allowed by the Commission, shall pay a penalty of \$500 to
7 the Commission for each day it is in default.

8 Any person who willfully makes any false report to the
9 Commission or to any member, officer, or employee thereof,
10 any person who willfully in a report withholds or fails to
11 provide material information to which the Commission is
12 entitled under this paragraph (8) and which information is
13 either required to be filed by statute, rule, regulation,
14 order, or decision of the Commission or has been requested
15 by the Commission, and any person who willfully aids or
16 abets such person shall be guilty of a Class A misdemeanor.

17 (h-3) Recoverable costs and revenue by the clean coal SNG
18 brownfield facility.

19 (1) A capital recovery charge approved by the
20 Commission shall be recoverable by the clean coal SNG
21 brownfield facility under a sourcing agreement. The
22 capital recovery charge shall be comprised of capital costs
23 and a reasonable rate of return. "Capital costs" means
24 costs to be incurred in connection with the construction
25 and development of a facility, as defined in Section 1-10
26 of the Illinois Power Agency Act, and such other costs as

1 the Capital Development Board deems appropriate to be
2 recovered in the capital recovery charge.

3 (A) Capital costs. The Capital Development Board
4 shall calculate a range of capital costs that it
5 believes would be reasonable for the clean coal SNG
6 brownfield facility to recover under the sourcing
7 agreement. In making this determination, the Capital
8 Development Board shall review the facility cost
9 report, if any, of the clean coal SNG brownfield
10 facility, adjusting the results based on the change in
11 the Annual Consumer Price Index for All Urban Consumers
12 for the Midwest Region as published in April by the
13 United States Department of Labor, Bureau of Labor
14 Statistics, the final draft of the sourcing agreement,
15 and the rate of return approved by the Commission. In
16 addition, the Capital Development Board may consult as
17 much as it deems necessary with the clean coal SNG
18 brownfield facility and conduct whatever research and
19 investigation it deems necessary.

20 The Capital Development Board shall retain an
21 engineering expert to assist in determining both the
22 range of capital costs and the range of operations and
23 maintenance costs that it believes would be reasonable
24 for the clean coal SNG brownfield facility to recover
25 under the sourcing agreement. Provided, however, that
26 such expert shall: (i) not have been involved in the

1 clean coal SNG brownfield facility's facility cost
2 report, if any, (ii) not own or control any direct or
3 indirect interest in the initial clean coal facility,
4 and (iii) have no contractual relationship with the
5 clean coal SNG brownfield facility. In order to qualify
6 as an independent expert, a person or company must
7 have:

8 (i) direct previous experience conducting
9 front-end engineering and design studies for
10 large-scale energy facilities and administering
11 large-scale energy operations and maintenance
12 contracts, which may be particularized to the
13 specific type of financing associated with the
14 clean coal SNG brownfield facility;

15 (ii) an advanced degree in economics,
16 mathematics, engineering, or a related area of
17 study;

18 (iii) ten years of experience in the energy
19 sector, including construction and risk management
20 experience;

21 (iv) expertise in assisting companies with
22 obtaining financing for large-scale energy
23 projects, which may be particularized to the
24 specific type of financing associated with the
25 clean coal SNG brownfield facility;

26 (v) expertise in operations and maintenance

1 which may be particularized to the specific type of
2 operations and maintenance associated with the
3 clean coal SNG brownfield facility;

4 (vi) expertise in credit and contract
5 protocols;

6 (vii) adequate resources to perform and
7 fulfill the required functions and
8 responsibilities; and

9 (viii) the absence of a conflict of interest
10 and inappropriate bias for or against an affected
11 gas utility or the clean coal SNG brownfield
12 facility.

13 The clean coal SNG brownfield facility and the
14 Illinois Power Agency shall cooperate with the Capital
15 Development Board in any investigation it deems
16 necessary. The Capital Development Board shall make
17 its final determination of the range of capital costs
18 confidentially and shall submit that range to the
19 Commission in a confidential filing within 120 days
20 after July 13, 2011 (the effective date of Public Act
21 97-096). The clean coal SNG brownfield facility shall
22 submit to the Commission its estimate of the capital
23 costs to be recovered under the sourcing agreement.
24 Only after the clean coal SNG brownfield facility has
25 submitted this estimate shall the Commission publicly
26 announce the range of capital costs submitted by the

1 Capital Development Board.

2 In the event that the estimate submitted by the
3 clean coal SNG brownfield facility is within or below
4 the range submitted by the Capital Development Board,
5 the clean coal SNG brownfield facility's estimate
6 shall be approved by the Commission as the amount of
7 capital costs to be recovered under the sourcing
8 agreement. In the event that the estimate submitted by
9 the clean coal SNG brownfield facility is above the
10 range submitted by the Capital Development Board, the
11 amount of capital costs at the lowest end of the range
12 submitted by the Capital Development Board shall be
13 approved by the Commission as the amount of capital
14 costs to be recovered under the sourcing agreement.
15 Within 15 days after the Capital Development Board has
16 submitted its range and the clean coal SNG brownfield
17 facility has submitted its estimate, the Commission
18 shall approve the capital costs for the clean coal SNG
19 brownfield facility.

20 The Capital Development Board shall monitor the
21 construction of the clean coal SNG brownfield facility
22 for the full duration of construction to assess
23 potential cost overruns. The Capital Development
24 Board, in its discretion, may retain an expert to
25 facilitate such monitoring. The clean coal SNG
26 brownfield facility shall pay a reasonable fee as

1 required by the Capital Development Board for the
2 Capital Development Board's services under this
3 subsection (h-3) to be deposited into the Capital
4 Development Board Revolving Fund, and such fee shall
5 not be passed through to a utility or its customers. If
6 an expert is retained by the Capital Development Board
7 for monitoring of construction, then the clean coal SNG
8 brownfield facility must pay for the expert's
9 reasonable fees and such costs shall not be passed
10 through to a utility or its customers.

11 (B) Rate of Return. No later than 30 days after the
12 date on which the Illinois Power Agency submits a final
13 draft sourcing agreement, the Commission shall hold a
14 public hearing to determine the rate of return to be
15 recovered under the sourcing agreement. Rate of return
16 shall be comprised of the clean coal SNG brownfield
17 facility's actual cost of debt, including
18 mortgage-style amortization, and a reasonable return
19 on equity. The Commission shall post notice of the
20 hearing on its website no later than 10 days prior to
21 the date of the hearing. The Commission shall provide
22 the public and all interested parties, including the
23 gas utilities, the Attorney General, and the Illinois
24 Power Agency, an opportunity to be heard.

25 In determining the return on equity, the
26 Commission shall select a commercially reasonable

1 return on equity taking into account the return on
2 equity being received by developers of similar
3 facilities in or outside of Illinois, the need to
4 balance an incentive for clean-coal technology with
5 the need to protect ratepayers from high gas prices,
6 the risks being borne by the clean coal SNG brownfield
7 facility in the final draft sourcing agreement, and any
8 other information that the Commission may deem
9 relevant. The Commission may establish a return on
10 equity that varies with the amount of savings, if any,
11 to customers during the term of the sourcing agreement,
12 comparing the delivered SNG price to a daily weighted
13 average price of natural gas, based upon an index. The
14 Illinois Power Agency shall recommend a return on
15 equity to the Commission using the same criteria.
16 Within 60 days after receiving the final draft sourcing
17 agreement from the Illinois Power Agency, the
18 Commission shall approve the rate of return for the
19 clean coal brownfield facility. Within 30 days after
20 obtaining debt financing for the clean coal SNG
21 brownfield facility, the clean coal SNG brownfield
22 facility shall file a notice with the Commission
23 identifying the actual cost of debt.

24 (2) Operations and maintenance costs approved by the
25 Commission shall be recoverable by the clean coal SNG
26 brownfield facility under the sourcing agreement. The

1 operations and maintenance costs mean costs that have been
2 incurred for the administration, supervision, operation,
3 maintenance, preservation, and protection of the clean
4 coal SNG brownfield facility's physical plant.

5 The Capital Development Board shall calculate a range
6 of operations and maintenance costs that it believes would
7 be reasonable for the clean coal SNG brownfield facility to
8 recover under the sourcing agreement, incorporating an
9 inflation index or combination of inflation indices to most
10 accurately reflect the actual costs of operating the clean
11 coal SNG brownfield facility. In making this
12 determination, the Capital Development Board shall review
13 the facility cost report, if any, of the clean coal SNG
14 brownfield facility, adjusting the results for inflation
15 based on the change in the Annual Consumer Price Index for
16 All Urban Consumers for the Midwest Region as published in
17 April by the United States Department of Labor, Bureau of
18 Labor Statistics, the final draft of the sourcing
19 agreement, and the rate of return approved by the
20 Commission. In addition, the Capital Development Board may
21 consult as much as it deems necessary with the clean coal
22 SNG brownfield facility and conduct whatever research and
23 investigation it deems necessary. As set forth in
24 subparagraph (A) of paragraph (1) of this subsection (h-3),
25 the Capital Development Board shall retain an independent
26 engineering expert to assist in determining both the range

1 of operations and maintenance costs that it believes would
2 be reasonable for the clean coal SNG brownfield facility to
3 recover under the sourcing agreement. The clean coal SNG
4 brownfield facility and the Illinois Power Agency shall
5 cooperate with the Capital Development Board in any
6 investigation it deems necessary. The Capital Development
7 Board shall make its final determination of the range of
8 operations and maintenance costs confidentially and shall
9 submit that range to the Commission in a confidential
10 filing within 120 days after July 13, 2011.

11 The clean coal SNG brownfield facility shall submit to
12 the Commission its estimate of the operations and
13 maintenance costs to be recovered under the sourcing
14 agreement. Only after the clean coal SNG brownfield
15 facility has submitted this estimate shall the Commission
16 publicly announce the range of operations and maintenance
17 costs submitted by the Capital Development Board. In the
18 event that the estimate submitted by the clean coal SNG
19 brownfield facility is within or below the range submitted
20 by the Capital Development Board, the clean coal SNG
21 brownfield facility's estimate shall be approved by the
22 Commission as the amount of operations and maintenance
23 costs to be recovered under the sourcing agreement. In the
24 event that the estimate submitted by the clean coal SNG
25 brownfield facility is above the range submitted by the
26 Capital Development Board, the amount of operations and

1 maintenance costs at the lowest end of the range submitted
2 by the Capital Development Board shall be approved by the
3 Commission as the amount of operations and maintenance
4 costs to be recovered under the sourcing agreement. Within
5 15 days after the Capital Development Board has submitted
6 its range and the clean coal SNG brownfield facility has
7 submitted its estimate, the Commission shall approve the
8 operations and maintenance costs for the clean coal SNG
9 brownfield facility.

10 The clean coal SNG brownfield facility shall pay for
11 the independent engineering expert's reasonable fees and
12 such costs shall not be passed through to a utility or its
13 customers. The clean coal SNG brownfield facility shall pay
14 a reasonable fee as required by the Capital Development
15 Board for the Capital Development Board's services under
16 this subsection (h-3) to be deposited into the Capital
17 Development Board Revolving Fund, and such fee shall not be
18 passed through to a utility or its customers.

19 (3) Sequestration costs approved by the Commission
20 shall be recoverable by the clean coal SNG brownfield
21 facility. "Sequestration costs" means costs to be incurred
22 by the clean coal SNG brownfield facility in accordance
23 with its Commission-approved carbon capture and
24 sequestration plan to:

25 (A) capture carbon dioxide;

26 (B) build, operate, and maintain a sequestration

1 site in which carbon dioxide may be injected;

2 (C) build, operate, and maintain a carbon dioxide
3 pipeline; and

4 (D) transport the carbon dioxide to the
5 sequestration site or a pipeline.

6 The Commission shall assess the prudence of the
7 sequestration costs for the clean coal SNG brownfield
8 facility before construction commences at the
9 sequestration site or pipeline. Any revenues the clean coal
10 SNG brownfield facility receives as a result of the
11 capture, transportation, or sequestration of carbon
12 dioxide shall be first credited against all sequestration
13 costs, with the positive balance, if any, treated as
14 additional net revenue.

15 The Commission may, in its discretion, retain an expert
16 to assist in its review of sequestration costs. The clean
17 coal SNG brownfield facility shall pay for the expert's
18 reasonable fees if an expert is retained by the Commission,
19 and such costs shall not be passed through to a utility or
20 its customers. Once made, the Commission's determination
21 of the amount of recoverable sequestration costs shall not
22 be increased unless the clean coal SNG brownfield facility
23 can show by clear and convincing evidence that (i) the
24 costs were not reasonably foreseeable; (ii) the costs were
25 due to circumstances beyond the clean coal SNG brownfield
26 facility's control; and (iii) the clean coal SNG brownfield

1 facility took all reasonable steps to mitigate the costs.
2 If the Commission determines that sequestration costs may
3 be increased, the Commission shall provide for notice and a
4 public hearing for approval of the increased sequestration
5 costs.

6 (4) Actual delivered and processed fuel costs shall be
7 set by the Illinois Power Agency through a SNG feedstock
8 procurement, pursuant to Sections 1-20, 1-77, and 1-78 of
9 the Illinois Power Agency Act, to be performed at least
10 every 5 years and purchased by the clean coal SNG
11 brownfield facility pursuant to feedstock procurement
12 contracts developed by the Illinois Power Agency, with coal
13 comprising at least 50% of the total feedstock over the
14 term of the sourcing agreement and petroleum coke
15 comprising the remainder of the SNG feedstock. If the
16 Commission fails to approve a feedstock procurement plan or
17 fails to approve the results of a feedstock procurement
18 event, then the fuel shall be purchased by the company
19 month-by-month on the spot market and those actual
20 delivered and processed fuel costs shall be recoverable
21 under the sourcing agreement. If a supplier defaults under
22 the terms of a procurement contract, then the Illinois
23 Power Agency shall immediately initiate a feedstock
24 procurement process to obtain a replacement supply, and,
25 prior to the conclusion of that process, fuel shall be
26 purchased by the company month-by-month on the spot market

1 and those actual delivered and processed fuel costs shall
2 be recoverable under the sourcing agreement.

3 (5) Taxes and fees imposed by the federal government,
4 the State, or any unit of local government applicable to
5 the clean coal SNG brownfield facility, excluding income
6 tax, shall be recoverable by the clean coal SNG brownfield
7 facility under the sourcing agreement to the extent such
8 taxes and fees were not applicable to the facility on July
9 13, 2011.

10 (6) The actual transportation costs, in accordance
11 with the applicable utility's tariffs, and third-party
12 marketer costs incurred by the company, if any, associated
13 with transporting the SNG from the clean coal SNG
14 brownfield facility to the Chicago City-gate to sell such
15 SNG into the natural gas markets shall be recoverable under
16 the sourcing agreement.

17 (7) Unless otherwise provided, within 30 days after a
18 decision of the Commission on recoverable costs under this
19 Section, any interested party to the Commission's decision
20 may apply for a rehearing with respect to the decision. The
21 Commission shall receive and consider the application for
22 rehearing and shall grant or deny the application in whole
23 or in part within 20 days after the date of the receipt of
24 the application by the Commission. If no rehearing is
25 applied for within the required 30 days or an application
26 for rehearing is denied, then the Commission decision shall

1 be final. If an application for rehearing is granted, then
2 the Commission shall hold a rehearing within 30 days after
3 granting the application. The decision of the Commission
4 upon rehearing shall be final.

5 Any person affected by a decision of the Commission
6 under this subsection (h-3) may have the decision reviewed
7 only under and in accordance with the Administrative Review
8 Law. Unless otherwise provided, the provisions of the
9 Administrative Review Law, all amendments and
10 modifications to that Law, and the rules adopted pursuant
11 to that Law shall apply to and govern all proceedings for
12 the judicial review of final administrative decisions of
13 the Commission under this subsection (h-3). The term
14 "administrative decision" is defined as in Section 3-101 of
15 the Code of Civil Procedure.

16 (8) The Capital Development Board shall adopt and make
17 public a policy detailing the process for retaining experts
18 under this Section. Any experts retained to assist with
19 calculating the range of capital costs or operations and
20 maintenance costs shall be retained no later than 45 days
21 after July 13, 2011.

22 (h-4) No later than 90 days after the Illinois Power Agency
23 submits the final draft sourcing agreement pursuant to
24 subsection (h-1), the Commission shall approve a sourcing
25 agreement containing (i) the capital costs, rate of return, and
26 operations and maintenance costs established pursuant to

1 subsection (h-3) and (ii) all other terms and conditions,
2 rights, provisions, exceptions, and limitations contained in
3 the final draft sourcing agreement; provided, however, the
4 Commission shall correct typographical and scrivener's errors
5 and modify the contract only as necessary to provide that the
6 gas utility does not have the right to terminate the sourcing
7 agreement due to any future events that may occur other than
8 the clean coal SNG brownfield facility's failure to timely meet
9 milestones, uncured default, extended force majeure, or
10 abandonment. Once the sourcing agreement is approved, then the
11 gas utility subject to that sourcing agreement shall have 45
12 days after the date of the Commission's approval to enter into
13 the sourcing agreement.

14 (h-5) Sequestration enforcement.

15 (A) All contracts entered into under subsection (h) of
16 this Section and all sourcing agreements under subsection
17 (h-1) of this Section, regardless of duration, shall
18 require the owner of any facility supplying SNG under the
19 contract or sourcing agreement to provide certified
20 documentation to the Commission each year, starting in the
21 facility's first year of commercial operation, accurately
22 reporting the quantity of carbon dioxide emissions from the
23 facility that have been captured and sequestered and
24 reporting any quantities of carbon dioxide released from
25 the site or sites at which carbon dioxide emissions were
26 sequestered in prior years, based on continuous monitoring

1 of those sites.

2 (B) If, in any year, the owner of the clean coal SNG
3 facility fails to demonstrate that the SNG facility
4 captured and sequestered at least 90% of the total carbon
5 dioxide emissions that the facility would otherwise emit or
6 that sequestration of emissions from prior years has
7 failed, resulting in the release of carbon dioxide into the
8 atmosphere, then the owner of the clean coal SNG facility
9 must pay a penalty of \$20 per ton of excess carbon dioxide
10 emissions not to exceed \$40,000,000, in any given year
11 which shall be deposited into the Energy Efficiency Trust
12 Fund and distributed pursuant to subsection (b) of Section
13 6-6 of the Renewable Energy, Energy Efficiency, and Coal
14 Resources Development Law of 1997. On or before the 5-year
15 anniversary of the execution of the contract and every 5
16 years thereafter, an expert hired by the owner of the
17 facility with the approval of the Attorney General shall
18 conduct an analysis to determine the cost of sequestration
19 of at least 90% of the total carbon dioxide emissions the
20 plant would otherwise emit. If the analysis shows that the
21 actual annual cost is greater than the penalty, then the
22 penalty shall be increased to equal the actual cost.
23 Provided, however, to the extent that the owner of the
24 facility described in subsection (h) of this Section can
25 demonstrate that the failure was as a result of acts of God
26 (including fire, flood, earthquake, tornado, lightning,

1 hurricane, or other natural disaster); any amendment,
2 modification, or abrogation of any applicable law or
3 regulation that would prevent performance; war; invasion;
4 act of foreign enemies; hostilities (regardless of whether
5 war is declared); civil war; rebellion; revolution;
6 insurrection; military or usurped power or confiscation;
7 terrorist activities; civil disturbance; riots;
8 nationalization; sabotage; blockage; or embargo, the owner
9 of the facility described in subsection (h) of this Section
10 shall not be subject to a penalty if and only if (i) it
11 promptly provides notice of its failure to the Commission;
12 (ii) as soon as practicable and consistent with any order
13 or direction from the Commission, it submits to the
14 Commission proposed modifications to its carbon capture
15 and sequestration plan; and (iii) it carries out its
16 proposed modifications in the manner and time directed by
17 the Commission.

18 If the Commission finds that the facility has not
19 satisfied each of these requirements, then the facility
20 shall be subject to the penalty. If the owner of the clean
21 coal SNG facility captured and sequestered more than 90% of
22 the total carbon dioxide emissions that the facility would
23 otherwise emit, then the owner of the facility may credit
24 such additional amounts to reduce the amount of any future
25 penalty to be paid. The penalty resulting from the failure
26 to capture and sequester at least the minimum amount of

1 carbon dioxide shall not be passed on to a utility or its
2 customers.

3 If the clean coal SNG facility fails to meet the
4 requirements specified in this subsection (h-5), then the
5 Attorney General, on behalf of the People of the State of
6 Illinois, shall bring an action to enforce the obligations
7 related to the facility set forth in this subsection (h-5),
8 including any penalty payments owed, but not including the
9 physical obligation to capture and sequester at least 90%
10 of the total carbon dioxide emissions that the facility
11 would otherwise emit. Such action may be filed in any
12 circuit court in Illinois. By entering into a contract
13 pursuant to subsection (h) of this Section, the clean coal
14 SNG facility agrees to waive any objections to venue or to
15 the jurisdiction of the court with regard to the Attorney
16 General's action under this subsection (h-5).

17 Compliance with the sequestration requirements and any
18 penalty requirements specified in this subsection (h-5)
19 for the clean coal SNG facility shall be assessed annually
20 by the Commission, which may in its discretion retain an
21 expert to facilitate its assessment. If any expert is
22 retained by the Commission, then the clean coal SNG
23 facility shall pay for the expert's reasonable fees, and
24 such costs shall not be passed through to the utility or
25 its customers. A SNG facility operating pursuant to this
26 subsection (h-5) shall not forfeit its designation as a

1 clean coal SNG facility or a clean coal SNG brownfield
2 facility if the facility fails to fully comply with the
3 applicable carbon sequestration ~~sequestration~~ requirements
4 in any given year, provided the requisite offsets are
5 purchased or requisite penalties are paid.

6 In addition, carbon dioxide emission credits received
7 by the clean coal SNG facility in connection with
8 sequestration of carbon dioxide from the facility must be
9 sold in a timely fashion with any revenue, less applicable
10 fees and expenses and any expenses required to be paid by
11 facility for carbon dioxide transportation or
12 sequestration, deposited into the reconciliation account
13 within 30 days after receipt of such funds by the owner of
14 the clean coal SNG facility.

15 The clean coal SNG facility is prohibited from
16 transporting or sequestering carbon dioxide unless the
17 owner of the carbon dioxide pipeline that transfers the
18 carbon dioxide from the facility and the owner of the
19 sequestration site where the carbon dioxide captured by the
20 facility is stored has acquired all applicable permits
21 under applicable State and federal laws, statutes, rules,
22 or regulations prior to the transfer or sequestration of
23 carbon dioxide. The responsibility for compliance with the
24 sequestration requirements specified in this subsection
25 (h-5) for the clean coal SNG facility shall reside solely
26 with the clean coal SNG facility, regardless of whether the

1 facility has contracted with another party to capture,
2 transport, or sequester carbon dioxide.

3 (C) If, in any year, the owner of a clean coal SNG
4 brownfield facility fails to demonstrate that the clean
5 coal SNG brownfield facility captured and sequestered at
6 least 85% of the total carbon dioxide emissions that the
7 facility would otherwise emit, then the owner of the clean
8 coal SNG brownfield facility must pay a penalty of \$20 per
9 ton of excess carbon emissions up to \$20,000,000, which
10 shall be deposited into the Energy Efficiency Trust Fund
11 and distributed pursuant to subsection (b) of Section 6-6
12 of the Renewable Energy, Energy Efficiency, and Coal
13 Resources Development Law of 1997. Provided, however, to
14 the extent that the owner of the clean coal SNG brownfield
15 facility can demonstrate that the failure was as a result
16 of acts of God (including fire, flood, earthquake, tornado,
17 lightning, hurricane, or other natural disaster); any
18 amendment, modification, or abrogation of any applicable
19 law or regulation that would prevent performance; war;
20 invasion; act of foreign enemies; hostilities (regardless
21 of whether war is declared); civil war; rebellion;
22 revolution; insurrection; military or usurped power or
23 confiscation; terrorist activities; civil disturbances;
24 riots; nationalization; sabotage; blockage; or embargo,
25 the owner of the clean coal SNG brownfield facility shall
26 not be subject to a penalty if and only if (i) it promptly

1 provides notice of its failure to the Commission; (ii) as
2 soon as practicable and consistent with any order or
3 direction from the Commission, it submits to the Commission
4 proposed modifications to its carbon capture and
5 sequestration plan; and (iii) it carries out its proposed
6 modifications in the manner and time directed by the
7 Commission. If the Commission finds that the facility has
8 not satisfied each of these requirements, then the facility
9 shall be subject to the penalty. If the owner of a clean
10 coal SNG brownfield facility demonstrates that the clean
11 coal SNG brownfield facility captured and sequestered more
12 than 85% of the total carbon emissions that the facility
13 would otherwise emit, the owner of the clean coal SNG
14 brownfield facility may credit such additional amounts to
15 reduce the amount of any future penalty to be paid. The
16 penalty resulting from the failure to capture and sequester
17 at least the minimum amount of carbon dioxide shall not be
18 passed on to a utility or its customers.

19 In addition to any penalty for the clean coal SNG
20 brownfield facility's failure to capture and sequester at
21 least its minimum sequestration requirement, the Attorney
22 General, on behalf of the People of the State of Illinois,
23 shall bring an action for specific performance of this
24 subsection (h-5). Such action may be filed in any circuit
25 court in Illinois. By entering into a sourcing agreement
26 pursuant to subsection (h-1) of this Section, the clean

1 coal SNG brownfield facility agrees to waive any objections
2 to venue or to the jurisdiction of the court with regard to
3 the Attorney General's action for specific performance
4 under this subsection (h-5).

5 Compliance with the sequestration requirements and
6 penalty requirements specified in this subsection (h-5)
7 for the clean coal SNG brownfield facility shall be
8 assessed annually by the Commission, which may in its
9 discretion retain an expert to facilitate its assessment.
10 If an expert is retained by the Commission, then the clean
11 coal SNG brownfield facility shall pay for the expert's
12 reasonable fees, and such costs shall not be passed through
13 to a utility or its customers.

14 Responsibility for compliance with the sequestration
15 requirements specified in this subsection (h-5) for the
16 clean coal SNG brownfield facility shall reside solely with
17 the clean coal SNG brownfield facility regardless of
18 whether the facility has contracted with another party to
19 capture, transport, or sequester carbon dioxide.

20 (h-7) Sequestration permitting, oversight, and
21 investigations.

22 (1) No clean coal facility or clean coal SNG brownfield
23 facility may transport or sequester carbon dioxide unless
24 the Commission approves the method of carbon dioxide
25 transportation or sequestration. Such approval shall be
26 required regardless of whether the facility has contracted

1 with another to transport or sequester the carbon dioxide.
2 Nothing in this subsection (h-7) shall release the owner or
3 operator of a carbon dioxide sequestration site or carbon
4 dioxide pipeline from any other permitting requirements
5 under applicable State and federal laws, statutes, rules,
6 or regulations.

7 (2) The Commission shall review carbon dioxide
8 transportation and sequestration methods proposed by a
9 clean coal facility or a clean coal SNG brownfield facility
10 and shall approve those methods it deems reasonable and
11 cost-effective. For purposes of this review,
12 "cost-effective" means a commercially reasonable price for
13 similar carbon dioxide transportation or sequestration
14 techniques. In determining whether sequestration is
15 reasonable and cost-effective, the Commission may consult
16 with the Illinois State Geological Survey and retain third
17 parties to assist in its determination, provided that such
18 third parties shall not own or control any direct or
19 indirect interest in the facility that is proposing the
20 carbon dioxide transportation or the carbon dioxide
21 sequestration method and shall have no contractual
22 relationship with that facility. If a third party is
23 retained by the Commission, then the facility proposing the
24 carbon dioxide transportation or sequestration method
25 shall pay for the expert's reasonable fees, and these costs
26 shall not be passed through to a utility or its customers.

1 No later than 6 months prior to the date upon which the
2 owner intends to commence construction of a clean coal
3 facility or the clean coal SNG brownfield facility, the
4 owner of the facility shall file with the Commission a
5 carbon dioxide transportation or sequestration plan. The
6 Commission shall hold a public hearing within 30 days after
7 receipt of the facility's carbon dioxide transportation or
8 sequestration plan. The Commission shall post notice of the
9 review on its website upon submission of a carbon dioxide
10 transportation or sequestration method and shall accept
11 written public comments. The Commission shall take the
12 comments into account when making its decision.

13 The Commission may not approve a carbon dioxide
14 sequestration method if the owner or operator of the
15 sequestration site has not received (i) an Underground
16 Injection Control permit from the United States
17 Environmental Protection Agency, or from the Illinois
18 Environmental Protection Agency pursuant to the
19 Environmental Protection Act; (ii) an Underground
20 Injection Control permit from the Illinois Department of
21 Natural Resources pursuant to the Illinois Oil and Gas Act;
22 or (iii) an Underground Injection Control permit from the
23 United States Environmental Protection Agency or a permit
24 similar to items (i) or (ii) from the state in which the
25 sequestration site is located if the sequestration will
26 take place outside of Illinois. The Commission shall

1 approve or deny the carbon dioxide transportation or
2 sequestration method within 90 days after the receipt of
3 all required information.

4 (3) At least annually, the Illinois Environmental
5 Protection Agency shall inspect all carbon dioxide
6 sequestration sites in Illinois. The Illinois
7 Environmental Protection Agency may, as often as deemed
8 necessary, monitor and conduct investigations of those
9 sites. The owner or operator of the sequestration site must
10 cooperate with the Illinois Environmental Protection
11 Agency investigations of carbon dioxide sequestration
12 sites.

13 If the Illinois Environmental Protection Agency
14 determines at any time a site creates conditions that
15 warrant the issuance of a seal order under Section 34 of
16 the Environmental Protection Act, then the Illinois
17 Environmental Protection Agency shall seal the site
18 pursuant to the Environmental Protection Act. If the
19 Illinois Environmental Protection Agency determines at any
20 time a carbon dioxide sequestration site creates
21 conditions that warrant the institution of a civil action
22 for an injunction under Section 43 of the Environmental
23 Protection Act, then the Illinois Environmental Protection
24 Agency shall request the State's Attorney or the Attorney
25 General institute such action. The Illinois Environmental
26 Protection Agency shall provide notice of any such actions

1 as soon as possible on its website. The SNG facility shall
2 incur all reasonable costs associated with any such
3 inspection or monitoring of the sequestration sites, and
4 these costs shall not be recoverable from utilities or
5 their customers.

6 (4) (Blank).

7 (h-9) The clean coal SNG brownfield facility shall have the
8 right to recover prudently incurred increased costs or reduced
9 revenue resulting from any new or amendatory legislation or
10 other action. The State of Illinois pledges that the State will
11 not enact any law or take any action to:

12 (1) break, or repeal the authority for, sourcing
13 agreements approved by the Commission and entered into
14 between public utilities and the clean coal SNG brownfield
15 facility;

16 (2) deny public utilities full cost recovery for their
17 costs incurred under those sourcing agreements; or

18 (3) deny the clean coal SNG brownfield facility full
19 cost and revenue recovery as provided under those sourcing
20 agreements that are recoverable pursuant to subsection
21 (h-3) of this Section.

22 These pledges are for the benefit of the parties to those
23 sourcing agreements and the issuers and holders of bonds or
24 other obligations issued or incurred to finance or refinance
25 the clean coal SNG brownfield facility. The clean coal SNG
26 brownfield facility is authorized to include and refer to these

1 pledges in any financing agreement into which it may enter in
2 regard to those sourcing agreements.

3 The State of Illinois retains and reserves all other rights
4 to enact new or amendatory legislation or take any other
5 action, without impairment of the right of the clean coal SNG
6 brownfield facility to recover prudently incurred increased
7 costs or reduced revenue resulting from the new or amendatory
8 legislation or other action, including, but not limited to,
9 such legislation or other action that would (i) directly or
10 indirectly raise the costs the clean coal SNG brownfield
11 facility must incur; (ii) directly or indirectly place
12 additional restrictions, regulations, or requirements on the
13 clean coal SNG brownfield facility; (iii) prohibit
14 sequestration in general or prohibit a specific sequestration
15 method or project; or (iv) increase minimum sequestration
16 requirements for the clean coal SNG brownfield facility to the
17 extent technically feasible. The clean coal SNG brownfield
18 facility shall have the right to recover prudently incurred
19 increased costs or reduced revenue resulting from the new or
20 amendatory legislation or other action as described in this
21 subsection (h-9).

22 (h-10) Contract costs for SNG incurred by an Illinois gas
23 utility are reasonable and prudent and recoverable through the
24 purchased gas adjustment clause and are not subject to review
25 or disallowance by the Commission. Contract costs are costs
26 incurred by the utility under the terms of a contract that

1 incorporates the terms stated in subsection (h) of this Section
2 as confirmed in writing by the Illinois Power Agency as set
3 forth in subsection (h) of this Section, which confirmation
4 shall be deemed conclusive, or as a consequence of or condition
5 to its performance under the contract, including (i) amounts
6 paid for SNG under the SNG contract and (ii) costs of
7 transportation and storage services of SNG purchased from
8 interstate pipelines under federally approved tariffs. The
9 Illinois gas utility shall initiate a clean coal SNG facility
10 rider mechanism that (A) shall be applicable to all customers
11 who receive transportation service from the utility, (B) shall
12 be designed to have an equal percentage impact on the
13 transportation services rates of each class of the utility's
14 total customers, and (C) shall accurately reflect the net
15 customer savings, if any, and above market costs, if any, under
16 the SNG contract. Any contract, the terms of which have been
17 confirmed in writing by the Illinois Power Agency as set forth
18 in subsection (h) of this Section and the performance of the
19 parties under such contract cannot be grounds for challenging
20 prudence or cost recovery by the utility through the purchased
21 gas adjustment clause, and in such cases, the Commission is
22 directed not to consider, and has no authority to consider, any
23 attempted challenges.

24 The contracts entered into by Illinois gas utilities
25 pursuant to subsection (h) of this Section shall provide that
26 the utility retains the right to terminate the contract without

1 further obligation or liability to any party if the contract
2 has been impaired as a result of any legislative,
3 administrative, judicial, or other governmental action that is
4 taken that eliminates all or part of the prudence protection of
5 this subsection (h-10) or denies the recoverability of all or
6 part of the contract costs through the purchased gas adjustment
7 clause. Should any Illinois gas utility exercise its right
8 under this subsection (h-10) to terminate the contract, all
9 contract costs incurred prior to termination are and will be
10 deemed reasonable, prudent, and recoverable as and when
11 incurred and not subject to review or disallowance by the
12 Commission. Any order, issued by the State requiring or
13 authorizing the discontinuation of the merchant function,
14 defined as the purchase and sale of natural gas by an Illinois
15 gas utility for the ultimate consumer in its service territory
16 shall include provisions necessary to prevent the impairment of
17 the value of any contract hereunder over its full term.

18 (h-11) All costs incurred by an Illinois gas utility in
19 procuring SNG from a clean coal SNG brownfield facility
20 pursuant to subsection (h-1) or a third-party marketer pursuant
21 to subsection (h-1) are reasonable and prudent and recoverable
22 through the purchased gas adjustment clause in conjunction with
23 a SNG brownfield facility rider mechanism and are not subject
24 to review or disallowance by the Commission; provided that if a
25 utility is required by law or otherwise elects to connect the
26 clean coal SNG brownfield facility to an interstate pipeline,

1 then the utility shall be entitled to recover pursuant to its
2 tariffs all just and reasonable costs that are prudently
3 incurred. Sourcing agreement costs are costs incurred by the
4 utility under the terms of a sourcing agreement that
5 incorporates the terms stated in subsection (h-1) of this
6 Section as approved by the Commission as set forth in
7 subsection (h-4) of this Section, which approval shall be
8 deemed conclusive, or as a consequence of or condition to its
9 performance under the contract, including (i) amounts paid for
10 SNG under the SNG contract and (ii) costs of transportation and
11 storage services of SNG purchased from interstate pipelines
12 under federally approved tariffs. Any sourcing agreement, the
13 terms of which have been approved by the Commission as set
14 forth in subsection (h-4) of this Section, and the performance
15 of the parties under the sourcing agreement cannot be grounds
16 for challenging prudence or cost recovery by the utility, and
17 in these cases, the Commission is directed not to consider, and
18 has no authority to consider, any attempted challenges.

19 (h-15) Reconciliation account. The clean coal SNG facility
20 shall establish a reconciliation account for the benefit of the
21 retail customers of the utilities that have entered into
22 contracts with the clean coal SNG facility pursuant to
23 subsection (h). The reconciliation account shall be maintained
24 and administered by an independent trustee that is mutually
25 agreed upon by the owners of the clean coal SNG facility, the
26 utilities, and the Commission in an interest-bearing account in

1 accordance with the following:

2 (1) The clean coal SNG facility shall conduct an
3 analysis annually within 60 days after receiving the
4 necessary cost information, which shall be provided by the
5 gas utility within 6 months after the end of the preceding
6 calendar year, to determine (i) the average annual contract
7 SNG cost, which shall be calculated as the total amount
8 paid for SNG purchased from the clean coal SNG facility
9 over the preceding 12 months, plus the cost to the utility
10 of the required transportation and storage services of SNG,
11 divided by the total number of MMBtus of SNG actually
12 purchased from the clean coal SNG facility in the preceding
13 12 months under the utility contract; (ii) the average
14 annual natural gas purchase cost, which shall be calculated
15 as the total annual supply costs paid for baseload natural
16 gas (excluding any SNG) purchased by such utility over the
17 preceding 12 months plus the costs of transportation and
18 storage services of such natural gas (excluding such costs
19 for SNG), divided by the total number of MMBtus of baseload
20 natural gas (excluding SNG) actually purchased by the
21 utility during the year; (iii) the cost differential, which
22 shall be the difference between the average annual contract
23 SNG cost and the average annual natural gas purchase cost;
24 and (iv) the revenue share target which shall be the cost
25 differential multiplied by the total amount of SNG
26 purchased over the preceding 12 months under such utility

1 contract.

2 (A) To the extent the annual average contract SNG
3 cost is less than the annual average natural gas
4 purchase cost, the utility shall credit an amount equal
5 to the revenue share target to the reconciliation
6 account. Such credit payment shall be made monthly
7 starting within 30 days after the completed analysis in
8 this subsection (h-15) and based on collections from
9 all customers via a line item charge in all customer
10 bills designed to have an equal percentage impact on
11 the transportation services of each class of
12 customers. Credit payments made pursuant to this
13 subparagraph (A) shall be deemed prudent and
14 reasonable and not subject to Commission prudence
15 review.

16 (B) To the extent the annual average contract SNG
17 cost is greater than the annual average natural gas
18 purchase cost, the reconciliation account shall be
19 used to provide a credit equal to the revenue share
20 target to the utilities to be used to reduce the
21 utility's natural gas costs through the purchased gas
22 adjustment clause. Such payment shall be made within 30
23 days after the completed analysis pursuant to this
24 subsection (h-15), but only to the extent that the
25 reconciliation account has a positive balance.

26 (2) At the conclusion of the term of the SNG contracts

1 pursuant to subsection (h) and the completion of the final
2 annual analysis pursuant to this subsection (h-15), to the
3 extent the facility owes any amount to retail customers,
4 amounts in the account shall be credited to retail
5 customers to the extent the owed amount is repaid; 50% of
6 any additional amount in the reconciliation account shall
7 be distributed to the utilities to be used to reduce the
8 utilities' natural gas costs through the purchase gas
9 adjustment clause with the remaining amount distributed to
10 the clean coal SNG facility. Such payment shall be made
11 within 30 days after the last completed analysis pursuant
12 to this subsection (h-15). If the facility has repaid all
13 owed amounts, if any, to retail customers and has
14 distributed 50% of any additional amount in the account to
15 the utilities, then the owners of the clean coal SNG
16 facility shall have no further obligation to the utility or
17 the retail customers.

18 If, at the conclusion of the term of the contracts
19 pursuant to subsection (h) and the completion of the final
20 annual analysis pursuant to this subsection (h-15), the
21 facility owes any amount to retail customers and the
22 account has been depleted, then the clean coal SNG facility
23 shall be liable for any remaining amount owed to the retail
24 customers. The clean coal SNG facility shall market the
25 daily production of SNG and distribute on a monthly basis
26 5% of the amounts collected with respect to such future

1 sales to the utilities in proportion to each utility's SNG
2 contract to be used to reduce the utility's natural gas
3 costs through the purchase gas adjustment clause; such
4 payments to the utility shall continue until either 15
5 years after the conclusion of the contract or such time as
6 the sum of such payments equals the remaining amount owed
7 to the retail customers at the end of the contract,
8 whichever is earlier. If the debt to the retail customers
9 is not repaid within 15 years after the conclusion of the
10 contract, then the owner of the clean coal SNG facility
11 must sell the facility, and all proceeds from that sale
12 must be used to repay any amount owed to the retail
13 customers under this subsection (h-15).

14 The retail customers shall have first priority in
15 recovering that debt above any creditors, except the
16 secured lenders to the extent that the secured lenders have
17 any secured debt outstanding, including any parent
18 companies or affiliates of the clean coal SNG facility.

19 (3) 50% of all additional net revenue, defined as
20 miscellaneous net revenue after cost allowance and above
21 the budgeted estimate established for revenue pursuant to
22 subsection (h), including sale of substitute natural gas
23 derived from the clean coal SNG facility above the
24 nameplate capacity of the facility and other by-products
25 produced by the facility, shall be credited to the
26 reconciliation account on an annual basis with such payment

1 made within 30 days after the end of each calendar year
2 during the term of the contract.

3 (4) The clean coal SNG facility shall each year,
4 starting in the facility's first year of commercial
5 operation, file with the Commission, in such form as the
6 Commission shall require, a report as to the reconciliation
7 account. The annual report must contain the following
8 information:

9 (A) the revenue share target amount;

10 (B) the amount credited or debited to the
11 reconciliation account during the year;

12 (C) the amount credited to the utilities to be used
13 to reduce the utilities natural gas costs though the
14 purchase gas adjustment clause;

15 (D) the total amount of reconciliation account at
16 the beginning and end of the year;

17 (E) the total amount of consumer savings to date;
18 and

19 (F) any additional information the Commission may
20 require.

21 When any report is erroneous or defective or appears to the
22 Commission to be erroneous or defective, the Commission may
23 notify the clean coal SNG facility to amend the report within
24 30 days; before or after the termination of the 30-day period,
25 the Commission may examine the trustee of the reconciliation
26 account or the officers, agents, employees, books, records, or

1 accounts of the clean coal SNG facility and correct such items
2 in the report as upon such examination the Commission may find
3 defective or erroneous. All reports shall be under oath.

4 All reports made to the Commission by the clean coal SNG
5 facility and the contents of the reports shall be open to
6 public inspection and shall be deemed a public record under the
7 Freedom of Information Act. Such reports shall be preserved in
8 the office of the Commission. The Commission shall publish an
9 annual summary of the reports prior to February 1 of the
10 following year. The annual summary shall be made available to
11 the public on the Commission's website and shall be submitted
12 to the General Assembly.

13 Any facility that fails to file the report required under
14 this paragraph (4) to the Commission within the time specified
15 or to make specific answer to any question propounded by the
16 Commission within 30 days after the time it is lawfully
17 required to do so, or within such further time not to exceed 90
18 days as may be allowed by the Commission in its discretion,
19 shall pay a penalty of \$500 to the Commission for each day it
20 is in default.

21 Any person who willfully makes any false report to the
22 Commission or to any member, officer, or employee thereof, any
23 person who willfully in a report withholds or fails to provide
24 material information to which the Commission is entitled under
25 this paragraph (4) and which information is either required to
26 be filed by statute, rule, regulation, order, or decision of

1 the Commission or has been requested by the Commission, and any
2 person who willfully aids or abets such person shall be guilty
3 of a Class A misdemeanor.

4 (h-20) The General Assembly authorizes the Illinois
5 Finance Authority to issue bonds to the maximum extent
6 permitted to finance coal gasification facilities described in
7 this Section, which constitute both "industrial projects"
8 under Article 801 of the Illinois Finance Authority Act and
9 "clean coal and energy projects" under Sections 825-65 through
10 825-75 of the Illinois Finance Authority Act.

11 Administrative costs incurred by the Illinois Finance
12 Authority in performance of this subsection (h-20) shall be
13 subject to reimbursement by the clean coal SNG facility on
14 terms as the Illinois Finance Authority and the clean coal SNG
15 facility may agree. The utility and its customers shall have no
16 obligation to reimburse the clean coal SNG facility or the
17 Illinois Finance Authority for any such costs.

18 (h-25) The State of Illinois pledges that the State may not
19 enact any law or take any action to (1) break or repeal the
20 authority for SNG purchase contracts entered into between
21 public gas utilities and the clean coal SNG facility pursuant
22 to subsection (h) of this Section or (2) deny public gas
23 utilities their full cost recovery for contract costs, as
24 defined in subsection (h-10), that are incurred under such SNG
25 purchase contracts. These pledges are for the benefit of the
26 parties to such SNG purchase contracts and the issuers and

1 holders of bonds or other obligations issued or incurred to
2 finance or refinance the clean coal SNG facility. The
3 beneficiaries are authorized to include and refer to these
4 pledges in any finance agreement into which they may enter in
5 regard to such contracts.

6 (h-30) The State of Illinois retains and reserves all other
7 rights to enact new or amendatory legislation or take any other
8 action, including, but not limited to, such legislation or
9 other action that would (1) directly or indirectly raise the
10 costs that the clean coal SNG facility must incur; (2) directly
11 or indirectly place additional restrictions, regulations, or
12 requirements on the clean coal SNG facility; (3) prohibit
13 sequestration in general or prohibit a specific sequestration
14 method or project; or (4) increase minimum sequestration
15 requirements.

16 (i) If a gas utility or an affiliate of a gas utility has
17 an ownership interest in any entity that produces or sells
18 synthetic natural gas, Article VII of this Act shall apply.

19 (Source: P.A. 96-1364, eff. 7-28-10; 97-96, eff. 7-13-11;
20 97-239, eff. 8-2-11; 97-630, eff. 12-8-11; 97-906, eff. 8-7-12;
21 97-1081, eff. 8-24-12; revised 1-24-13.)

22 (220 ILCS 5/9-244.5 new)

23 Sec. 9-244.5. Natural gas infrastructure investment and
24 modernization; regulatory reform.

25 (a) The General Assembly recognizes that for well over a

1 century Illinois residents and businesses have been
2 well-served by and have benefitted from a comprehensive natural
3 gas utility system. The General Assembly finds that natural gas
4 utilities are now entering a new construction cycle that is
5 needed to refurbish, rebuild, modernize, and expand systems to
6 continue to provide safe, reliable, and affordable service to
7 the State's current and future utility customers. In
8 particular, the General Assembly finds that it is the policy of
9 this State that significant investments must be made in the
10 State's natural gas transmission and distribution system over
11 the next 10 years to modernize and upgrade transmission and
12 distribution facilities in the State. These investments will
13 ensure that the State's natural gas utility infrastructure will
14 promote future economic development and job creation in the
15 State and that the State's natural gas utilities will be able
16 to continue to provide quality natural gas service to their
17 customers. These investments may include innovative
18 technological offerings that will create and promote savings
19 opportunities for customers by providing them with additional
20 use of modern natural gas-fired appliances that will enhance
21 customer experience and timely data that allows them to make
22 more informed decisions concerning their gas usage and may
23 enhance customers' ability to use energy efficient equipment
24 dependent on a modernized system. Additionally these
25 investments will also ensure that the State's gas transmission,
26 distribution, and underground gas storage systems and related

1 natural gas utility infrastructure are modernized and upgraded
2 and continue to be safe and reliable. The introduction of
3 performance metrics will further ensure that reliability and
4 other indicators are not just maintained but improved over the
5 next decade.

6 The General Assembly further finds that regulatory reform
7 measures that increase predictability, stability, and
8 transparency in the ratemaking process are needed to promote
9 prudent, long-term infrastructure investment and to mutually
10 benefit the State's natural gas utilities and their customers,
11 regulators, and investors.

12 (b) For purposes of this Section, "participating utility"
13 means a natural gas utility serving fewer than 1,100,000
14 customers as of January 1, 2013, or a combination utility that
15 voluntarily elects and commits to undertake (i) the
16 infrastructure investment program consisting of the
17 commitments and obligations described in this subsection (b),
18 and (ii) the customer assistance program consisting of the
19 commitments and obligations described in subsection (b-10) of
20 this Section, notwithstanding any other provisions of this Act
21 and without obtaining any approvals from the Commission or any
22 other agency other than as set forth in this Section,
23 regardless of whether any such approval would otherwise be
24 required. "Combination utility" means a utility that, as of
25 January 1, 2012, provided electric service to at least
26 1,000,000 retail customers in Illinois and gas service to at

1 least 500,000 retail customers in Illinois. A participating
2 utility shall recover the expenditures made under the
3 infrastructure investment program through the ratemaking
4 process, including, but not limited to, the performance-based
5 formula rate and process set forth in this Section. Illinois
6 natural gas utilities that are affiliated by virtue of a common
7 parent company, at the utilities' request, shall be considered
8 a single gas utility for the sole purposes of determining: (1)
9 if the utilities created the required number of full-time
10 equivalent jobs and made the required level of investment under
11 this subsection (b); (2) if the utilities exceeded the maximum
12 level of investment under subsection (b-5) of this Section; (3)
13 the required level of the utilities' contributions under
14 subsection (b-10) of this Section; and (4) if these utilities
15 have satisfied the performance metrics under subsection (f-2)
16 of this Section.

17 During the infrastructure investment program's peak
18 program year, a participating utility, other than a combination
19 utility, serving fewer than 1,100,000 customers on January 1,
20 2013, shall create 1,000 full-time equivalent jobs in Illinois,
21 such jobs measured by reference to the participating utility's
22 average number of employees for the years 2008, 2009, and 2010
23 as reported in the applicable Form 21 ILCC and the
24 participating utility's average number of contractor positions
25 for the years 2008, 2009, and 2010 and related to the provision
26 of natural gas service; and a participating utility that is a

1 combination utility shall create 250 full-time equivalent jobs
2 in Illinois, such jobs measured by reference to the
3 participating utility's average number of employees for the
4 years 2009, 2010, and 2011 as reported in the applicable Form
5 21 ILCC and the participating utility's total number of
6 contractor positions as of December 31 of the year immediately
7 preceding the 10-year investment period and related to the
8 provision of natural gas service. These full-time equivalent
9 jobs shall include direct jobs, contractor positions, and
10 induced jobs. A portion of the full-time equivalent jobs
11 created by each participating utility shall include
12 incremental personnel not accounted for in the baseline
13 calculated under this paragraph that have been subsequently
14 hired or retained. For purposes of this Section, "peak program
15 year" means the consecutive 12-month period with the highest
16 number of full-time equivalent jobs that occurs between the
17 beginning of investment year 2 and the end of investment year
18 4.

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

21 (1) Beginning no later than 180 days after a
22 participating utility that is a combination utility files a
23 performance-based formula rate tariff pursuant to
24 subsection (c) of this Section the participating utility
25 shall, except as otherwise provided in this subsection (b)
26 over a 10-year period, invest an estimated \$330,000,000 in

1 gas transmission, distribution, and underground storage
2 system upgrades, modernization and compliance projects,
3 and training facilities, including, but not limited to:

4 (i) distribution plant, including mains, services,
5 meters, regulators, measuring and regulating station
6 equipment, and structures and improvements;

7 (ii) transmission plant, including mains,
8 measuring and regulating station equipment, and
9 structures and improvements;

10 (iii) underground storage plant, including
11 compression station equipment and structures,
12 measuring and regulating station structures and
13 equipment, reservoirs, wells, lines, and gas
14 purification equipment;

15 (iv) state of the art gas transmission and
16 distribution control facility;

17 (v) training facilities;

18 (vi) gas advanced metering infrastructure meters
19 including associated cyber secure data communication
20 network; and

21 (vii) small volume transport.

22 (2) Beginning no later than 180 days after a
23 participating utility serving fewer than 1,100,000
24 customers on January 1, 2013 that is not a combination
25 utility files a performance-based formula rate tariff
26 pursuant to subsection (c) of this Section the

1 participating utility shall, except as otherwise provided
2 in this subsection (b) over a 10-year period, invest an
3 estimated \$1,200,000,000 in gas transmission,
4 distribution, and underground storage system upgrades, and
5 modernization and compliance projects, including, but not
6 limited to:

7 (i) distribution plant, including mains, services,
8 meters, regulators, measuring and regulating station
9 equipment, and structures and improvements;

10 (ii) transmission plant, including mains,
11 measuring and regulating station equipment, and
12 structures and improvements;

13 (iii) underground storage plant, including
14 compression station equipment and structures,
15 measuring and regulating station structures and
16 equipment, reservoirs, wells, lines, and gas
17 purification equipment; and

18 (iv) liquefied natural gas plant, including
19 structures and improvements, gas holders, liquefaction
20 equipment, and vaporizing equipment.

21 The investments in the infrastructure investment program
22 described in this subsection (b) shall be incremental to the
23 participating utility's annual capital investment program, as
24 defined by, for purposes of this subsection (b), the
25 participating utility's average capital spend for calendar
26 years 2009, 2010, and 2011 as reported in Form 21 ILCC, except

1 in the case of a participating utility that is not a
2 combination utility, serving fewer than 1,100,000 customers on
3 January 1, 2013, for which the investments in the
4 infrastructure program described in this subsection (b) shall
5 be incremental to the participating utility's annual capital
6 investment program, as defined by, for purposes of this
7 subsection (b), the participating utility's average capital
8 spend for calendar years 2008, 2009, and 2010 as reported in
9 the applicable Form 21 ILCC; provided that where one or more
10 utilities have merged, the average capital spend shall be
11 determined using the aggregate of the merged utilities' capital
12 spend reported in Form 21 ILCC for the years 2009, 2010, and
13 2011, as applicable. A participating utility may add a
14 reasonable construction ramp-up and ramp-down time to the
15 investment periods specified in this subsection (b). For each
16 such investment period, the ramp-up and ramp-down time shall
17 not exceed a total of 6 months.

18 Within 60 days after filing a tariff under subsection (c)
19 of this Section, a participating utility shall submit to the
20 Commission its plan, including scope, schedule, and staffing,
21 for satisfying its infrastructure investment program
22 commitments pursuant to this subsection (b). The submitted plan
23 shall include a schedule and staffing plan for the next
24 calendar year. The plan need not allocate the work equally over
25 the respective periods, but should allocate material
26 increments throughout such periods commensurate with the work

1 to be undertaken. No later than April 1 of each subsequent
2 year, the participating utility shall submit to the Commission
3 a report that includes any updates to the plan, a schedule for
4 the next calendar year, the expenditures made for the prior
5 calendar year and cumulatively, and the number of full time
6 equivalent jobs created for the prior calendar year and
7 cumulatively. If the participating utility is materially
8 deficient in satisfying a schedule or staffing plan, then the
9 report must also include a corrective action plan to address
10 the deficiency. The fact that the plan, implementation of the
11 plan, or a schedule changes shall not imply the imprudence or
12 unreasonableness of the infrastructure investment program,
13 plan, or schedule. Further, no later than 45 days following the
14 last day of the first, second, and third quarters of each year
15 of the plan, a participating utility shall submit to the
16 Commission a verified quarterly report for the prior quarter
17 that includes (i) the total number of full-time equivalent jobs
18 created during the prior quarter, (ii) the total number of
19 employees as of the last day of the prior quarter, (iii) the
20 total number of full-time equivalent hours in each job
21 classification or job title, (iv) the total number of
22 incremental employees and contractors in support of the
23 investments undertaken pursuant to this subsection (b) for the
24 prior quarter, and (v) any other information that the
25 Commission may require by rule.

26 With respect to the participating utility's peak job

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

21 With respect to the participating utility's investment
22 amount commitments, if, after considering the participating
23 utility's corrective action plan and compliance thereunder,
24 the Commission enters an order finding, after notice and
25 hearing, that a participating utility is not satisfying its
26 investment amount commitments described in this subsection

1 (b), then the participating utility shall no longer be eligible
2 to annually update the performance-based formula rate tariff
3 pursuant to subsection (d) of this Section. In such event, the
4 then current rates shall remain in effect until such time as
5 new rates are set pursuant to Article IX of this Act, subject
6 to retroactive adjustment, with interest, to reconcile rates
7 charged with actual costs.

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

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

25 (b-5) Nothing in this Section shall prohibit the Commission
26 from investigating the prudence and reasonableness of the

1 expenditures made under the infrastructure investment program
2 during the annual review required by subsection (d) of this
3 Section and shall, as part of such investigation, determine
4 whether the participating utility's actual costs under the
5 program are prudent and reasonable. The fact that a
6 participating utility invests more than the minimum amounts
7 specified in subsection (b) of this Section or its plan shall
8 not imply imprudence or unreasonableness.

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

20 In no event, absent General Assembly approval, shall the
21 capital investment costs incurred by a participating utility,
22 other than a combination utility, serving fewer than 1,100,000
23 customers on January 1, 2013, in satisfying its infrastructure
24 investment program commitments described in subsection (b) of
25 this Section exceed \$2,500,000,000 or, for a participating
26 utility that is a combination utility, \$380,000,000. If the

1 participating utility's updated cost estimates for satisfying
2 its infrastructure investment program commitments described in
3 subsection (b) exceed the limitation imposed by this paragraph,
4 then it shall submit a report to the Commission that identifies
5 the increased costs and explains the reason or reasons for the
6 increased costs no later than the year in which the
7 participating utility estimates it will exceed the limitation.
8 The Commission shall review the report and shall, within 90
9 days after the participating utility files the report, report
10 to the General Assembly its findings regarding the
11 participating utility's report. If the General Assembly does
12 not amend the limitation imposed by this paragraph, then the
13 participating utility may modify its plan so as not to exceed
14 the limitation imposed by this paragraph, and may propose
15 corresponding changes to the metrics established pursuant to
16 subsection (f-1) or (f-2), as applicable, of this Section, and
17 the Commission may modify the metrics and incremental savings
18 goals established pursuant to subsection (f-1) or (f-2), as
19 applicable, of this Section accordingly.

20 (b-10) All participating utilities shall make
21 contributions for an energy low-income and support program or
22 programs in accordance with this subsection. Beginning no later
23 than 180 days after a participating utility files a
24 performance-based formula rate tariff pursuant to subsection
25 (c) of this Section and without obtaining any approvals from
26 the Commission or any other agency other than as set forth in

1 this Section, regardless of whether any such approval would
2 otherwise be required, a participating utility shall pay
3 \$500,000 per year for 10 years to the energy low-income and
4 support program or programs, which is intended to fund customer
5 assistance programs with the primary purpose being avoidance of
6 imminent disconnection. Such programs may include:

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

12 (2) a program that provides grants and other bill
13 payment concessions to disabled veterans who demonstrate a
14 hardship and members of the armed services or reserve
15 forces of the United States or members of the Illinois
16 National Guard who are on active duty pursuant to an
17 executive order of the President of the United States, an
18 act of the Congress of the United States, or an order of
19 the Governor and who demonstrate a hardship;

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

24 (4) a non-residential special hardship program that
25 provides grants to non-residential customers such as small
26 businesses and non-profit organizations that demonstrate a

1 hardship, including those providing services to senior
2 citizen and low-income customers; and

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

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

12 Programs that use funds that are provided by a
13 participating utility to reduce utility bills may be
14 implemented through tariffs that are filed with and reviewed by
15 the Commission. If a utility elects to file tariffs with the
16 Commission to implement all or a portion of the programs, those
17 tariffs shall, regardless of the date actually filed, be deemed
18 accepted and approved, and shall become effective on the
19 effective date of this amendatory Act of the 98th General
20 Assembly. The participating utility shall file annual reports
21 documenting the disbursement of those funds under this Section
22 with the Commission. The Commission has the authority to audit
23 disbursement of the funds to ensure they were disbursed
24 consistently with this Section.

25 If the Commission finds that a participating utility is no
26 longer eligible to update the performance-based formula rate

1 tariff pursuant to subsection (d) of this Section, or the
2 performance-based formula rate is otherwise terminated, then
3 the participating utility's voluntary commitments and
4 obligations under this subsection (b-10) shall immediately
5 terminate.

6 (c) A participating utility may elect to recover its
7 delivery services cost through a performance-based formula
8 rate approved by the Commission, which shall specify the cost
9 components that form the basis of the rate charged to customers
10 with sufficient specificity to operate in a standardized manner
11 and be updated annually with transparent information that
12 reflects the participating utility's actual costs to be
13 recovered during the applicable rate year, which is the period
14 beginning with the first billing day of January and extending
15 through the last billing day of the following December. In the
16 event the participating utility recovers a portion of its costs
17 through automatic adjustment clause tariffs on the effective
18 date of this amendatory Act of the 98th General Assembly, the
19 participating utility may elect to continue to recover these
20 costs through such automatic adjustment clause tariffs, but
21 then these costs shall not be recovered through the
22 performance-based formula rate, or the participating utility
23 may elect to file at any time to terminate any or all such
24 automatic adjustment clause tariffs and the Commission shall
25 approve such filing no later than 45 days after such filing.

26 For purposes of this Section, including subsection (g),

1 "delivery services" means those services provided by the gas
2 utility that are necessary in order for the gas storage,
3 transmission, and distribution systems to function so that
4 retail customers located in the gas utility's service area can
5 receive gas supply from the gas utility or, to the extent
6 authorized by statute, Commission rule, or the gas utility's
7 tariffs, from suppliers other than the gas utility, and shall
8 include, without limitation, standard metering and billing
9 services; provided, however, that solely for purposes of
10 subsection (g), costs of delivery services shall not include
11 charges assessed to retail customers under any tariff for
12 recovery of costs of clean up or remediation of manufactured
13 gas plant sites or any tariff for recovery of energy efficiency
14 costs and excludes reconciliation adjustments determined under
15 subsection (d) of this Section.

16 In the event the participating utility, prior to the
17 effective date of this amendatory Act of the 98th General
18 Assembly, filed gas delivery services tariffs with the
19 Commission pursuant to Section 9-201 of this Act that are
20 related to the recovery of its gas delivery services costs that
21 are still pending on the effective date of this amendatory Act
22 of the 98th General Assembly, the participating utility may, at
23 the time it files its performance-based formula rate tariff
24 with the Commission, also file a notice of withdrawal with the
25 Commission to withdraw the gas delivery services tariffs
26 previously filed pursuant to Section 9-201 of this Act. Upon

1 receipt of such notice, the Commission shall dismiss with
2 prejudice any docket that had been initiated to investigate the
3 gas delivery services tariffs filed pursuant to Section 9-201
4 of this Act, and such tariffs and the record related thereto
5 shall not be the subject of any further hearing, investigation,
6 or proceeding of any kind related to rates for gas delivery
7 services except that the rate case expense incurred by the
8 participating utility with respect to such tariffs through the
9 date of dismissal of such docket shall be recoverable through
10 the performance-based formula rate tariff, regardless of the
11 year in which the rate case expense was incurred. The
12 participating utility shall attest to the amount of the rate
13 case expense by verification from an officer, and such amount
14 shall not be disallowed.

15 The performance-based formula rate shall be implemented
16 through a tariff filed with the Commission consistent with the
17 provisions of this subsection (c) that shall be applicable to
18 all customers, excluding customers taking service under
19 contracts entered into pursuant to Section 9-102.1 of this Act.
20 The Commission shall initiate and conduct an investigation of
21 the tariff in a manner consistent with the provisions of this
22 subsection (c) and the provisions of Article IX of this Act to
23 the extent they do not conflict with this subsection (c).
24 Except in the case where the Commission finds, after notice and
25 hearing, that a participating utility is not satisfying its
26 investment amount commitments under subsection (b) of this

1 Section, the performance-based formula rate shall remain in
2 effect at the discretion of the participating utility. The
3 performance-based formula rate approved by the Commission
4 shall do the following:

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

13 (2) Reflect the participating utility's actual
14 year-end capital structure for the applicable calendar
15 year, excluding goodwill, subject to a determination of
16 prudence and reasonableness consistent with Commission
17 practice and law, except that the common equity ratio in
18 the year-end capital structure for the applicable calendar
19 year shall not be subject to a determination of prudence
20 and reasonableness where said ratio is within 200 basis
21 points of the common equity ratio approved by the
22 Commission and reflected in the most recent Final Order
23 resolving a participating utility's request for a general
24 rate increase entered prior to the enactment of this
25 Section.

26 (3) Include a cost of equity, which shall be calculated

1 as the sum of the following:

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

7 (B) 580 basis points.

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

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

19 (A) recovery of incentive compensation expense
20 that is based on the achievement of operational
21 metrics, including metrics related to budget controls,
22 safety, customer service, efficiency and productivity,
23 and environmental compliance, each of which may be
24 measured specifically for the participating utility or
25 for the corporation of which the participating utility
26 is a part. Incentive compensation expense that is based

1 on net income or an affiliate's earnings per share
2 shall not be recoverable under the performance-based
3 formula rate;

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

7 (C) recovery of severance costs, provided that if
8 the amount is over \$3,700,000 for a participating
9 utility, then the full amount shall be amortized
10 consistent with subparagraph (F) of this paragraph (4)
11 of this subsection (c);

12 (D) investment return at a rate equal to the
13 utility's weighted average cost of long-term debt on
14 the pension assets, net of deferred tax benefits, and
15 on any associated regulatory asset. "Pension asset"
16 means the excess, if any, of cumulative contributions
17 by the utility to a pension trust over cumulative
18 recognized pension expense. The "pension asset" is
19 determined as the net of following items, where items
20 (i) and (ii) combined represent the funded status of
21 the participating utility's pension plans recognized
22 on the participating utility's balance sheet, and
23 where item (iii) represents the components of pension
24 expense not yet recorded in earnings, but recognized
25 separately on the participating utility's balance
26 sheet;

1 (i) cumulative contributions made by the
2 participating utility in a pension trust in
3 compliance with its obligations under its defined
4 benefit pension plans and any associated
5 investment earnings, gains, and losses;

6 (ii) the participating utility's projected
7 pension obligations calculated in accordance with
8 U.S. Generally Accepted Accounting Principles;

9 (iii) the participating utility's
10 pension-related regulatory assets or regulatory
11 liabilities representing unrecognized components
12 of pension cost and accounted for in accordance
13 with U.S. Generally Accepted Accounting
14 Principles;

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

26 (F) amortization over a 5-year period of the full

1 amount of each charge or credit that exceeds \$3,700,000
2 for a participating utility in the applicable calendar
3 year and that relates to a workforce reduction
4 program's severance costs, changes in accounting
5 rules, changes in law, compliance with any
6 Commission-initiated audit, or a single system event
7 or other similar expense, provided that any
8 unamortized balance shall be reflected in rate base.
9 For purposes of this subparagraph (F), changes in law
10 include any enactment, repeal, or amendment in a law,
11 ordinance, rule, regulation, interpretation, permit,
12 license, consent, or order, including those relating
13 to taxes, accounting, or to environmental matters, or
14 in the interpretation or application thereof by any
15 governmental authority occurring after the effective
16 date of this amendatory Act of the 98th General
17 Assembly;

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

20 (H) historical weather normalized billing
21 determinants; and

22 (I) allocation methods for common costs.

23 (5) Provide that if the participating utility's earned
24 rate of return on common equity related to the provision of
25 delivery services for the prior rate year (calculated using
26 costs and capital structure approved by the Commission as

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

1 but not limited to, adjustments for goodwill, and after any
2 Commission-ordered disallowances and taxes) is more than
3 50 basis points less than the return on common equity
4 calculated pursuant to paragraph (3) of this subsection (c)
5 (after adjusting for any penalties to the rate of return on
6 common equity applied pursuant to the performance metrics
7 provision of subsection (f) of this Section), then the
8 participating utility shall apply a charge through the
9 performance-based formula rate that reflects an amount
10 equal to the value of that portion of the earned rate of
11 return on common equity that is more than 50 basis points
12 less than the rate of return on common equity calculated
13 pursuant to paragraph (3) of this subsection (c) (after
14 adjusting for any penalties to the rate of return on common
15 equity applied pursuant to the performance metrics
16 provision of subsection (f) of this Section) for the prior
17 rate year, adjusted for taxes.

18 (6) Provide for annual reconciliations, as described
19 in subsection (d) of this Section, with interest, of the
20 delivery services component of revenue as reported in the
21 applicable Form 21 ILCC, excluding any reconciliation
22 adjustments under subsection (d) of this Section and any
23 adjustments under paragraph (5) of subsection (c) of this
24 Section, for each calendar year, beginning with the
25 calendar year in which the participating utility files its
26 performance-based formula rate tariff pursuant to

1 subsection (c) of this Section, with what the revenue
2 requirement would have been had the actual cost information
3 for the applicable calendar year been available at the
4 filing date.

5 The participating utility shall file, together with its
6 tariff, final data based on its most recently filed Form 21
7 ILCC, plus projected plant additions and correspondingly
8 updated depreciation reserve and expense for the calendar year
9 in which the tariff and data are filed, that shall populate the
10 performance-based formula rate and set the initial rates under
11 the formula. For purposes of this Section, "Form 21 ILCC" means
12 the Annual Report of Electric Utilities, Licensees and/or
13 Natural Gas Utilities" or any successor to that report that
14 natural gas utilities are required to file with the Commission
15 under Section 5-109 of this Act. Nothing in this Section is
16 intended to allow costs that are not otherwise recoverable to
17 be recoverable by virtue of inclusion in Form 21 ILCC or to
18 authorize the Commission to alter Form 21 ILCC in a manner that
19 would result in a level of cost recovery inconsistent with the
20 intent of this Section.

21 After the participating utility files its proposed
22 performance-based formula rate structure and protocols and
23 initial rates, the Commission shall initiate a docket to review
24 the filing. The Commission shall enter an order approving, or
25 approving as modified, the performance-based formula rate,
26 including the initial rates, as just and reasonable within 270

1 days after the date on which the tariff was filed, or, if the
2 tariff is filed within 14 days after the effective date of this
3 amendatory Act of the 98th General Assembly, then by May 31,
4 2014. Such review shall be based on the same evidentiary
5 standards, including, but not limited to, those concerning the
6 prudence and reasonableness of the costs incurred by the
7 participating utility, the Commission applies in a hearing to
8 review a filing for a general increase in rates under Article
9 IX of this Act. The initial rates shall take effect within 30
10 days after the Commission's order approving the
11 performance-based formula rate tariff.

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

19 Subsequent changes to the performance-based formula rate
20 structure or protocols shall be made as set forth in Section
21 9-201 of this Act, but nothing in this subsection (c) is
22 intended to limit the Commission's authority under Article IX
23 and other provisions of this Act to initiate an investigation
24 of a participating utility's performance-based formula rate
25 tariff, provided that any such changes shall be consistent with
26 paragraphs (1) through (6) of this subsection (c). Any change

1 ordered by the Commission shall be made at the same time new
2 rates take effect following the Commission's next order
3 pursuant to subsection (d) of this Section, provided that the
4 new rates take effect no less than 30 days after the date on
5 which the Commission issues an order adopting the change.

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

10 In the event the performance-based formula rate is
11 terminated, the then current rates shall remain in effect until
12 such time as new rates are set pursuant to Article IX of this
13 Act, subject to retroactive rate adjustment, with interest, to
14 reconcile rates charged with actual costs. At such time that
15 the performance-based formula rate is terminated, the
16 participating utility's voluntary commitments and obligations
17 under subsection (b) of this Section shall immediately
18 terminate, except for the participating utility's obligation
19 to pay an amount already owed to the fund for training grants
20 pursuant to a Commission order issued under subsection (b) of
21 this Section.

22 (d) The participating utility shall file, on or before May
23 1 of each year, with the Chief Clerk of the Commission, its
24 updated cost inputs to the performance-based formula rate for
25 the applicable rate year and the corresponding new charges.
26 Each such filing shall conform to the following requirements

1 and include the following information:

2 (1) The inputs to the performance-based formula rate
3 for the applicable rate year shall be based on final
4 historical data reflected in the participating utility's
5 most recently filed annual Form 21 ILCC, plus projected
6 plant additions and correspondingly updated depreciation
7 reserve and expense for the calendar year in which the
8 inputs are filed. The filing shall also include a
9 reconciliation of the delivery services component of
10 revenue as reported in the applicable Form 21 ILCC,
11 excluding any reconciliation adjustments under subsection
12 (d) of this Section and any adjustments under paragraph (5)
13 of subsection (c) of this Section, for each calendar year,
14 beginning with the calendar year in which the participating
15 utility files its performance-based formula rate tariff
16 pursuant to subsection (c) of this Section, for the prior
17 rate year with the actual revenue requirement for the prior
18 rate year (determined using a year-end rate base) that uses
19 amounts reflected in the applicable Form 21 ILCC that
20 reports the actual costs for the prior rate year. Any
21 over-collection or under-collection indicated by such
22 reconciliations shall be reflected as a credit against, or
23 recovered as an additional charge to, respectively, with
24 interest calculated at a rate equal to the utility's
25 weighted average cost of capital approved by the Commission
26 for the prior rate year, the charges for the applicable

1 rate year. Provided, however, that the first such
2 reconciliation shall be for the calendar year in which the
3 participating utility files its performance-based formula
4 rate tariff pursuant to subsection (c) of this Section and
5 shall reconcile (i) the delivery services component of
6 revenue as reported in the applicable Form 21 ILCC for such
7 calendar year with (ii) the revenue requirement determined
8 using a year-end rate base for that calendar year
9 calculated pursuant to the performance-based formula rate
10 using (A) actual costs for that year as reflected in the
11 applicable Form 21 ILCC, and, (B) for the first such
12 reconciliation only, the cost of equity, which shall be
13 calculated as the sum of 590 basis points plus the average
14 for the applicable calendar year of the monthly average
15 yields of 30-year U.S. Treasury bonds published by the
16 Board of Governors of the Federal Reserve System in its
17 weekly H.15 Statistical Release or successor publication.
18 The first such reconciliation is not intended to provide
19 for the recovery of costs previously excluded from rates
20 based on a prior Commission order finding of imprudence or
21 unreasonableness. Each reconciliation shall be certified
22 by the participating utility in the same manner that Form
23 21 ILCC is certified. The filing shall also include the
24 charge or credit, if any, resulting from the calculation
25 required by paragraph (6) of subsection (c) of this
26 Section.

1 Notwithstanding anything that may be to the contrary,
2 the intent of the reconciliations is to ultimately
3 reconcile the delivery services component of revenue as
4 reported in the applicable Form 21 ILCC for such calendar
5 year, excluding any reconciliation adjustments under
6 subsection (d) of this Section and any adjustments under
7 paragraph (5) of subsection (c) of this Section, for each
8 calendar year, beginning with the calendar year in which
9 the participating utility files its performance-based
10 formula rate tariff pursuant to subsection (c) of this
11 Section, with what the revenue requirement determined
12 using a year-end rate base for the applicable calendar year
13 would have been had actual cost information for the
14 applicable calendar year been available at the filing date.

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

21 (3) The filing shall include relevant and necessary
22 data and documentation for the applicable rate year that is
23 consistent with the Commission's rules applicable to a
24 filing for a general increase in rates or any rules adopted
25 by the Commission to implement this Section. Normalization
26 adjustments shall not be required. Notwithstanding any

1 other provision of this Section or Act or any rule or other
2 requirement adopted by the Commission, a participating
3 utility that is a combination utility with more than one
4 rate zone shall not be required to file a separate set of
5 such data and documentation for each rate zone and may
6 combine such data and documentation into a single set of
7 schedules.

8 Within 45 days after the participating utility files its
9 annual update of cost inputs to the performance-based formula
10 rate, the Commission shall have the authority, either upon
11 complaint or its own initiative, but with reasonable notice, to
12 enter upon a hearing concerning the prudence and reasonableness
13 of the costs incurred by the participating utility to be
14 recovered during the applicable rate year that are reflected in
15 the inputs to the performance-based formula rate derived from
16 the participating utility's Form 21 ILCC. During the course of
17 the hearing, each objection shall be stated with particularity
18 and evidence provided in support thereof, after which the
19 participating utility shall have the opportunity to rebut the
20 evidence. Discovery shall be allowed consistent with the
21 Commission's Rules of Practice, which Rules shall be enforced
22 by the Commission or the assigned hearing examiner. The
23 Commission shall apply the same evidentiary standards,
24 including, but not limited to, those concerning the prudence
25 and reasonableness of the costs incurred by the participating
26 utility, in the hearing as it would apply in a hearing to

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

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

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

7 (e) Nothing in subsection (c) or (d) of this Section shall
8 prohibit the Commission from investigating, or a participating
9 utility from filing, revenue-neutral tariff changes related to
10 rate design and cost allocation methodology of a
11 performance-based formula rate that has been placed into effect
12 for the participating utility. Following approval of a
13 participating utility's performance-based formula rate tariff
14 pursuant to subsection (c) of this Section, the participating
15 utility shall make a filing with the Commission within one year
16 after the effective date of the performance-based formula rate
17 tariff that proposes changes to the tariff to incorporate the
18 findings of any final rate design orders of the Commission
19 applicable to the participating utility and entered subsequent
20 to the Commission's approval of the tariff. The Commission
21 shall, after notice and hearing, enter its order approving, or
22 approving with modification, the proposed changes to the
23 performance-based formula rate tariff within 240 days after the
24 participating utility's filing. Following such approval, the
25 participating utility shall make a filing with the Commission
26 during each subsequent 3-year period that either proposes

1 revenue-neutral tariff changes or re-files the existing
2 tariffs without change, which shall present the Commission with
3 an opportunity to suspend the tariffs and consider
4 revenue-neutral tariff changes related to rate design.

5 (f) Within 30 days after the filing of a tariff pursuant to
6 subsection (c) of this Section, each participating utility
7 shall develop and file with the Commission multi-year metrics
8 designed as follows:

9 (f-1) For each participating utility that is a combination
10 utility, the following metrics shall be designed to achieve,
11 ratably (i.e., in equal segments, unless otherwise specified)
12 over a 10-year period, improvement over baseline performance
13 values as follows:

14 (1) System Integrity Improvement (under 49 CFR Part
15 192): Reduce the number of outstanding, non-hazardous
16 (Class 3) underground gas leaks on a participating
17 utility's gas system by 20% using a baseline of 2012.

18 (2) System Integrity Improvement (under 49 CFR 192):
19 Reduce the time period for leakage surveys on all
20 distribution pipelines that operate at 250 psig or greater
21 from every 5 years to once each calendar year, not to
22 exceed 15 months, that are in a Class 3 or Class 4
23 Location.

24 (3) Public Education and Emergency Responders: 100%
25 increase in the number of annual face to face informational
26 and training meetings to enhance education and provide

1 appropriate pipeline safety information to all
2 stakeholders, including emergency responders, public
3 officials, excavators, customers, safety advocates, and
4 members of the public living in the vicinity of pipelines,
5 using 2012 as a baseline.

6 (4) Third Party Excavation Damage: Reduce third party
7 excavation damage with a 10% reduction in the number of
8 damages per 1000 locate requests for natural gas
9 facilities, using a baseline of 2012.

10 (5) Integrity Management: Beginning in year 2 of the
11 participating utility's 10-year performance metric period,
12 install or replace 65 miles of gas transmission pipeline
13 facilities to upgrade and modernize the gas delivery
14 infrastructure and establish records and maximum allowable
15 operating pressures in accordance with Federal Department
16 of Transportation regulations. Install automatic or remote
17 controlled shut-off valves, or equivalent technology,
18 where economically, technically, and operationally
19 feasible on transmission pipelines constructed or entirely
20 replaced.

21 (6) Gas System Performance Monitoring: Increase the
22 number of new and upgraded gas transmission and
23 distribution system remote monitoring devices by 20% to
24 enhance and expand system pressure monitoring capabilities
25 and data acquisition, using a baseline of 2012.

26 (7) Reduction in Issuance of Estimated Gas Bills: 50%

1 improvement using a baseline of the average number of
2 estimated gas bills for the years 2009 through 2011.

3 (8) Opportunities for minority-owned and female-owned
4 business enterprises: Design a performance metric
5 regarding the creation of opportunities for minority-owned
6 and female-owned business enterprises consistent with
7 state and Federal law using a base performance value of the
8 percentage of the participating utility's capital
9 expenditures that were paid to minority-owned and
10 female-owned business enterprises in 2011.

11 (f-2) For each participating utility serving fewer than
12 1,100,000 customers on January 1, 2013, that is not a
13 combination utility, to achieve, over a 10-year period,
14 improvement over baseline performance values as follows:

15 (1) System Integrity Improvement (under 49 CFR Part
16 192): Reduce the number of outstanding, non-hazardous
17 (Class 3) underground gas leaks on a participating
18 utility's gas system by 10% using a baseline of 2012.

19 (2) System Integrity Improvement: Reduce the number of
20 bare steel, cast iron, ductile iron, copper and Cellulose
21 Acetate Butyrate (CAB) plastic service pipes on a
22 participating utility's gas system by 30% using a baseline
23 of 2012.

24 (3) Public Education and Emergency Responders: 100%
25 increase in the number of annual face to face informational
26 and training meetings to enhance education and provide

1 appropriate pipeline safety information to all
2 stakeholders, including emergency responders, public
3 officials, excavators, customers, safety advocates, and
4 members of the public living in the vicinity of pipelines,
5 using a baseline of 2012.

6 (4) Third Party Excavation Damage: Reduce third party
7 excavation damage, with a 5% reduction in the number of
8 damages per 1,000 locate requests for natural gas
9 facilities, using a baseline of 2012.

10 (5) Integrity Management: Install 900 miles of gas
11 pipeline facilities to upgrade and modernize the gas
12 delivery infrastructure and establish records and maximum
13 allowable operating pressures in accordance with the
14 United States Department of Transportation regulations.
15 Install automatic or remote controlled shut-off valves, or
16 equivalent technology, where economically, technically,
17 and operationally feasible, on transmission pipelines
18 constructed or entirely replaced.

19 (6) Gas System Performance Monitoring: Increase the
20 number of new and upgraded gas transmission and
21 distribution system remote monitoring devices by 20% to
22 enhance and expand system pressure monitoring capabilities
23 and data acquisition, using a baseline of 2012.

24 (7) Opportunities for minority-owned and female-owned
25 business enterprises: Design a performance metric
26 regarding the creation of opportunities for minority-owned

1 and female-owned business enterprises consistent with
2 state and Federal law using a base performance value of the
3 percentage of the participating utility's capital
4 expenditures that were paid to minority-owned and
5 female-owned business enterprises in 2011.

6 The metrics shall include incremental performance goals
7 for each year of the 10-year period, which shall be designed to
8 demonstrate that the participating utility is on track to
9 achieve the performance goal in each category at the end of the
10 10-year period. The participating utility shall elect when the
11 10-year period shall commence for the metrics set forth in this
12 subsection (f), provided that it begins no later than 14 months
13 following the date on which the participating utility begins
14 investing pursuant to subsection (b) of this Section.

15 (f-5) The financial penalties applicable to the metrics
16 described in subparagraphs (1) through (7) of subsection (f-1)
17 shall be applied through an adjustment to the participating
18 utility's return on equity of no more than a total of 30 basis
19 points in each of the first 3 years, of no more than a total of
20 34 basis points in each of the 3 years thereafter, and no more
21 than a total of 38 basis points in each of the 4 years
22 thereafter, as follows:

23 (1) With respect to each of the incremental annual
24 performance goals established pursuant to subparagraph (1)
25 of subsection (f-1), for each year that a participating
26 utility does not achieve each such goal, the participating

1 utility's return of equity shall be reduced as follows:
2 during year one, by 10 basis points; during years 2 and 3,
3 by 5 basis points; during years 4 through 6, by 6 basis
4 points; and during years 7 through 10, by 7 basis points.

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

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

21 (4) With respect to each of the incremental annual
22 performance goals established pursuant to subparagraphs
23 (3) and (4) of subsection (f-1), the performance under each
24 goal shall be calculated in terms of the percentage of the
25 goal achieved. The percentage goal achieved for each of the
26 goals shall be aggregated and an average percentage value

1 calculated, for each year of the 10-year period. If the
2 participating utility does not achieve an average
3 percentage value for a given year of at least 100%, the
4 participating utility's return on equity shall be reduced
5 by 5 basis points.

6 (5) With respect to each of the incremental annual
7 performance goals established pursuant to subparagraph (7)
8 of subsection (f-1), for each year that a participating
9 utility does not achieve each such goal, the participating
10 utility's return on equity shall be reduced by 5 basis
11 points.

12 (f-6) The financial penalties applicable to the metrics
13 described in subparagraphs (1) through (6) of subsection (f-2)
14 shall be applied through an adjustment to the participating
15 utility's return on equity of no more than a total of 30 basis
16 points in each of the first 3 years, of no more than a total of
17 34 basis points in each of the 3 years thereafter, and no more
18 than a total of 38 basis points in each of the 4 years
19 thereafter, as follows:

20 (1) With respect to each of the incremental annual
21 performance goals established pursuant to subparagraphs
22 (1), (2), (5), and (6) of subsection (f-2), for each year
23 that a participating utility does not achieve each such
24 goal, the participating utility's return on equity shall be
25 reduced as follows: during years one through 3, by 5 basis
26 points; during years 4 through 6, by 6 basis points; and

1 during years 7 through 10, by 7 basis points.

2 (2) With respect to each of the incremental annual
3 performance goals established pursuant to subparagraphs
4 (3) and (4) of subsection (f-2), the performance under each
5 goal shall be calculated in terms of the percentage of the
6 goal achieved. The percentage goal achieved for each of the
7 goals shall be aggregated and an average percentage value
8 calculated, for each year of the 10-year period. If the
9 participating utility does not achieve an average
10 percentage value for a given year of at least 100%, the
11 participating utility's return on equity shall be reduced
12 by 10 basis points.

13 (f-8) The financial penalties shall be applied as described
14 in subsection (f-5) or (f-6), as applicable, for the 12-month
15 period in which the deficiency occurred through a separate
16 tariff mechanism, which shall be filed by the participating
17 utility together with its metrics. In the event the
18 performance-based formula rate tariff established pursuant to
19 subsection (c) of this Section terminates, the participating
20 utility's obligations under subsection (f-1) or (f-2), as
21 applicable, and subsection (f-5) or (f-6), as applicable, of
22 this Section and this subsection (f-8) shall also terminate,
23 provided, however, that the tariff mechanism established
24 pursuant to subsection (f) of this Section and subsection (f-5)
25 or (f-6), as applicable, and this subsection (f-8) shall remain
26 in effect until any penalties due and owing at the time of such

1 termination are applied.

2 The Commission shall, after notice and hearing, enter an
3 order within 120 days after the metrics are filed approving, or
4 approving with modification, a participating utility's tariff
5 or mechanism to satisfy the metrics set forth in subsection
6 (f-1) or (f-2), as applicable, of this Section and subsection
7 (f-5) or (f-6), as applicable, of this Section. On June 1 of
8 each subsequent year, each participating utility shall file a
9 report with the Commission that includes, among other things, a
10 description of how the participating utility performed under
11 each metric and an identification of any extraordinary events
12 that adversely impacted the participating utility's
13 performance. Whenever a participating utility does not satisfy
14 the metrics required pursuant to subsection (f-1) or (f-2), as
15 applicable, of this Section, the Commission shall, after notice
16 and hearing, enter an order approving financial penalties in
17 accordance with subsection (f-5) or (f-6), as applicable, of
18 this Section. The Commission-approved financial penalties
19 shall be applied beginning with the next rate year. Nothing in
20 this Section shall authorize the Commission to reduce or
21 otherwise obviate the imposition of financial penalties for
22 failing to achieve one or more of the metrics established
23 pursuant to subparagraphs (1) through (3) of subsection (f-1)
24 or (f-2), as applicable, of this Section.

25 (g) On or before June 30, 2016, each participating utility
26 shall file a report with the Commission that calculates the

1 2-year average percentage change in the average residential
2 retail customer's total bill over the 2-year period ended
3 December 31, 2015, that is attributable to a change in delivery
4 services charges, by comparing a base year and a comparison
5 year pursuant to the methodology specified in this subsection
6 (g). For a participating utility that is a combination utility
7 with more than one rate zone, the weighted average aggregate
8 change shall be provided. For a participating utility that has
9 separate delivery service rates for space heat and non-space
10 heat customers which are in effect in either or both the base
11 year and the comparison year, the space heat rates, when
12 applicable, shall be used for purposes of this calculation. The
13 report shall be filed together with a statement from an
14 independent auditor attesting to the accuracy of the report.
15 The cost of the independent auditor shall be borne by the
16 participating utility and shall not be a recoverable expense.

17 For purposes of all calculations performed under this
18 subsection (g), the average residential retail customer's
19 assumed annual consumption, for the base year and the
20 comparison year shall be assumed to be as follows: for a
21 participating utility that is a combination utility, 785
22 therms; and for a participating utility that is not a
23 combination utility and served fewer than 1,100,000 customers
24 on January 1, 2013, 1,100 therms.

25 The report filed with the Commission shall:

26 (1) Calculate an average residential retail customer's

1 total bill for natural gas service, expressed on a dollars
2 per year basis, for a base year using: (i) the average
3 residential retail customer's assumed annual consumption,
4 (ii) a delivery service charge, using the delivery service
5 rates in effect at the end of the December, 2013 billing
6 cycle, and (iii) a cost of gas supply, based on the
7 participating utility's average purchased gas adjustments
8 for the period 2008-2010, where such total bill for natural
9 gas service includes add-on taxes and riders.

10 (2) Calculate a delivery service charge for the base
11 year, using the average residential customer's assumed
12 annual consumption and the delivery service rates in effect
13 at the end of the December, 2013 billing cycle, where such
14 delivery service charge for natural gas service shall not
15 include add-on taxes and riders.

16 (3) Calculate a delivery service charge for the
17 comparison year, using the average residential customer's
18 assumed annual consumption and the delivery service rates
19 in effect at the end of the December, 2015 billing cycle,
20 where such delivery service charge for natural gas service
21 shall not include add-on taxes and riders. For purposes of
22 the calculation of the delivery service charge for the
23 comparison year any reconciliation adjustments determined
24 under subsection (d) of this Section shall be excluded by
25 multiplying each component of the delivery services rates
26 by a fraction whose denominator is the revenue requirement

1 that was used to derive the delivery service rates in
2 effect at the end of the December, 2015 billing cycle and
3 the numerator is this same revenue requirement adjusted to
4 remove any reconciliation for previous years.

5 (4) Calculate the 2-year average change in the average
6 residential retail customer's total bill attributable to a
7 change in delivery service charges by subtracting the
8 average residential retail customer's delivery service
9 charge in the base year from the average residential retail
10 customer's delivery service charge in the comparison year,
11 and dividing the result by the average residential retail
12 customer's total bill in the base year, and then dividing
13 the resulting percentage by 2.

14 In the event that the average annual increase for a
15 participating utility that is a combination utility exceeds
16 2.5% or for a participating utility that is not a combination
17 utility exceeds 5%, as calculated pursuant to this subsection
18 (g), then this Section of this Act, other than this subsection,
19 shall be inoperative as it relates to the participating utility
20 and its service area as of the date of the report due to be
21 submitted pursuant to this subsection (g) and the participating
22 utility shall no longer be eligible to annually update the
23 performance-based formula rate tariff pursuant to subsection
24 (d) of this Section. In such event, the then current rates
25 shall remain in effect until such time as new rates are set
26 pursuant to Article IX of this Act, subject to retroactive

1 adjustment, with interest, to reconcile rates charged with
2 actual costs, and the participating utility's voluntary
3 commitments and obligations under subsection (b) of this
4 Section shall immediately terminate, except for the
5 participating utility's obligation to pay an amount already
6 owed to the fund for training grants pursuant to a Commission
7 order issued under subsection (b) of this Section.

8 In the event that the average annual increase is 2.5% or
9 less or 5.0% or less, as applicable, as calculated pursuant to
10 this subsection (g), then the performance-based formula rate
11 shall remain in effect as set forth in this Section.

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

16 (h) This Section, other than this subsection (h), and
17 Section 19-150.6 of the Act, are inoperative after December 31,
18 2023, for every participating utility, after which time a
19 participating utility shall no longer be eligible to annually
20 update the performance-based formula rate tariff pursuant to
21 subsection (d) of this Section. At such time, the then current
22 rates shall remain in effect until such time as new rates are
23 set pursuant to Article IX of this Act, subject to retroactive
24 adjustment, with interest, to reconcile rates charged with
25 actual costs.

26 By December 31, 2023, the Commission shall prepare and file

1 with the General Assembly a report on the infrastructure
2 program and the performance-based formula rate. The report
3 shall include the change in the average amount per therm paid
4 by residential customers, as defined in subsection (g) of this
5 Section, between June 1, 2014 and May 31, 2023. The report
6 shall include separate sections for each participating
7 utility. The fact that this Section becomes inoperative as set
8 forth in this subsection shall not be construed to mean that
9 the Commission may reexamine or otherwise reopen prudence or
10 reasonableness determinations already made.

11 (i) Nothing in this Section is intended to legislatively
12 overturn the opinion issued in People ex rel. Lisa Madigan v.
13 Ill. Commerce Comm'n, Nos. 1-10-0936, 1-10-1790, 1-10-1846,
14 and 1-10-1852 cons. (Ill. App. Ct. 1st Dist. Sept. 30, 2011).
15 This amendatory Act of the 98th General Assembly shall not be
16 construed as creating a contract between the General Assembly
17 and the participating utility and shall not establish a
18 property right in the participating utility.

19 (j) While a participating utility may use, develop, and
20 maintain broadband systems and the delivery of broadband
21 services, voice-over-internet-protocol services,
22 telecommunications services, and cable and video programming
23 services for use in providing delivery services and Gas AMI
24 functionality or application to its retail customers,
25 including, but not limited to, the installation,
26 implementation and maintenance of Gas AMI system upgrades as

1 defined in Section 19-150.6 of this Act, a participating
2 utility is prohibited from offering to its retail customers
3 broadband services or the delivery of broadband services,
4 voice-over-internet-protocol services, telecommunications
5 services, or cable or video programming services, unless they
6 are part of a service directly related to delivery services or
7 Gas AMI functionality or applications as defined in Section
8 19-150.6 of this Act, and from recovering the costs of such
9 offerings from retail customers.

10 (220 ILCS 5/19-150.6 new)

11 Sec. 19-150.6. Provisions relating to Gas Advanced
12 Metering Infrastructure Deployment Plan.

13 (a) For purposes of this Section:

14 "Gas Advanced Metering Infrastructure" or "Gas AMI" means
15 the communications hardware and software and associated system
16 software that creates a network between advanced gas meters and
17 utility business systems and allows the collection and
18 distribution of gas-related information to customers and other
19 parties in addition to providing information to the utility
20 itself.

21 "Gas Advanced Metering Infrastructure Benefits" may
22 include, but are not limited to, the following:

23 (1) Reduction in estimated gas bills.

24 (2) Reduction in monthly and off-cycle meter reading
25 costs.

1 (3) Reduction in meter reprogramming costs due to
2 remote programmability.

3 (4) Reduction in unmetered and unbilled usage due to
4 earlier identification of meter problems and tampering.

5 (5) Reduction in vehicle emissions due to reduction in
6 manual meter reading.

7 (6) Improved and more timely information available to
8 customers to assist with energy management and cost
9 savings.

10 (7) Improved information for the development of new
11 energy efficiency programs.

12 (8) Improved information for more efficient gas system
13 operation.

14 (9) Improved safety of gas operations.

15 "Cost-beneficial" means a determination that the benefits
16 of a participating utility's Gas AMI Deployment Plan exceed the
17 costs of the Plan as initially filed with the Commission or as
18 subsequently modified by the Commission. This standard is met
19 if the present value of the total benefits of the Gas AMI
20 Deployment Plan exceeds the present value of the total costs of
21 the Gas AMI Deployment Plan. The total cost shall include all
22 utility costs reasonably associated with the Gas AMI Deployment
23 Plan. The total benefits shall include the sum of avoided
24 costs, including avoided utility operational costs, avoided
25 consumer commodity costs, and avoided societal costs
26 associated with the production and consumption of natural gas,

1 as well as other societal benefits, including reductions in the
2 emissions of harmful pollutants and associated avoided
3 health-related costs, other benefits associated with natural
4 gas energy efficiency measures.

5 "Participating utility" has the meaning set forth in
6 Section 9-244.5 of this Act.

7 (b) Each participating utility that has an investment plan
8 including Gas AMI under Section 9-244.5 of this Act shall file
9 a Gas AMI Deployment Plan with the Commission within 180 days
10 after the filing of a tariff pursuant to subsection (c) of
11 Section 9-244.5. The Gas AMI Deployment Plan shall provide for
12 investment over a 10-year period that is sufficient to
13 implement the Gas AMI Deployment Plan across its entire
14 delivery service territory in a manner that is consistent with
15 subsection (b) of Section 9-244.5 of this Act. The Gas AMI
16 Deployment Plan shall contain:

17 (1) the participating utility's Gas AMI vision
18 statement that is consistent with the goal of developing a
19 cost-beneficial Advanced Gas Metering Infrastructure;

20 (2) a statement of Gas AMI strategy that includes a
21 description of how the participating utility evaluates and
22 prioritizes technology choices to create customer value,
23 including a plan to enhance and enable customers' ability
24 to take advantage of Gas AMI functionality beginning at the
25 time an account has billed successfully on the Gas AMI
26 network;

1 (3) a deployment schedule and plan that includes
2 deployment of Gas AMI to all customers for a participating
3 utility other than a combination utility, and to 56% of all
4 customers for a participating utility that is a combination
5 utility;

6 (4) annual milestones and metrics for the purposes of
7 measuring the success of the Gas AMI Deployment Plan in
8 enabling Gas AMI functionality; and enhancing consumer
9 benefits from gas system upgrades; and

10 (5) a plan for consumer education to be implemented by
11 the participating utility.

12 The Gas AMI Deployment Plan shall include open standards
13 and internet protocol to the maximum extent possible consistent
14 with cyber-security, and shall maximize, to the extent
15 possible, a flexible gas meter platform that can accept remote
16 device upgrades and contain sufficient internal memory
17 capacity for additional storage capabilities, functions and
18 services without the need for physical access to the meter.

19 The Gas AMI Deployment Plan shall secure the privacy of
20 personal information and establish the right of consumers to
21 consent to the disclosure of personal energy information to
22 third parties through electronic, web-based, and other means in
23 accordance with State and Federal law and regulations regarding
24 consumer privacy and protection of consumer data.

25 After notice and hearing, the Commission shall, within 60
26 days of the filing of a Gas AMI Deployment Plan, issue its

1 order approving, or approving with modification, the Gas AMI
2 Deployment Plan if the Commission finds that the Gas AMI
3 Deployment Plan contains the information required in
4 paragraphs (1) through (5) of this subsection (b) and further
5 finds that the implementation of the Gas AMI Deployment Plan is
6 likely to be cost-beneficial. A participating utility's
7 decision to invest pursuant to a Gas AMI Deployment Plan
8 approved by the Commission shall not be subject to prudence
9 reviews in subsequent Commission proceedings. Nothing in this
10 subsection (b) is intended to limit the Commission's ability to
11 review the reasonableness of the costs incurred under the Gas
12 AMI Deployment Plan. A participating utility shall be allowed
13 to recover the reasonable costs it incurs in implementing a
14 Commission-approved Gas AMI Deployment Plan, including the
15 costs of retired meters and radio modules, and may recover such
16 costs through its tariffs, including the performance-based
17 formula rate tariff approved pursuant to subsection (c) of
18 Section 9-244.5 of this Act.

19 (c) The Gas AMI Deployment Plan shall secure the privacy of
20 the customer's personal information. "Personal information"
21 for this purpose consists of the customer's name, address,
22 telephone number or other personally identifying information,
23 as well as information about the customer's natural gas usage.
24 Utilities, their contractors or agents, and any third party who
25 comes into possession of such personal information shall not
26 disclose such personal information to be used in mailing lists

1 or to be used for other commercial purposes not reasonably
2 related to the conduct of the participating utility's business.
3 Utilities shall comply with the consumer privacy requirements
4 of the Personal Information Protection Act that are in effect
5 as of the effective date of this amendatory Act of the 98th
6 General Assembly and as amended thereafter.

7 (d) On April 1 of each year beginning the year following
8 approval of the participating utility's Gas AMI Deployment
9 Plan, each participating utility that has an investment plan
10 including Gas AMI under Section 9-244.5 of this Act shall
11 submit a report regarding the progress it has made toward
12 completing implementation of its Gas AMI Deployment Plan. This
13 report shall:

14 (1) describe the Gas AMI investments made during the
15 prior 12 months and the Gas AMI investments planned to be
16 made in the following 12 months;

17 (2) provide sufficient detail to determine the
18 participating utility's progress in meeting the metrics
19 and milestones identified by the participating utility in
20 its Gas AMI Deployment Plan; and

21 (3) identify any updates to the Gas AMI Deployment
22 Plan.

23 Within 21 days after the participating utility files its
24 annual report, the Commission shall have authority, either upon
25 complaint or its own initiative, but with reasonable notice, to
26 enter upon an investigation regarding the participating

1 utility's progress in implementing the Gas AMI Deployment Plan
2 as described in paragraph (1) of this subsection (d). If the
3 Commission finds, after notice and hearing, that the
4 participating utility's progress in implementing the Gas AMI
5 Deployment Plan is materially deficient for the given Plan
6 year, then the Commission shall issue an order requiring the
7 participating utility to devise a corrective action plan,
8 subject to Commission approval and oversight, to bring
9 implementation back on schedule consistent with the Gas AMI
10 Deployment Plan. The Commission's order must be entered within
11 90 days after the participating utility files its annual
12 report. If the Commission does not initiate an investigation
13 within 21 days after the participating utility files its annual
14 report, then the filing shall be deemed accepted by the
15 Commission. The participating utility shall not be required to
16 suspend implementation of its Gas AMI Deployment Plan during
17 any Commission investigation.

18 The participating utility's annual report regarding Gas
19 AMI Deployment Plan year 10 shall contain a statement verifying
20 that the implementation of its Gas AMI Deployment Plan is
21 complete, provided, however, that if the participating utility
22 is subject to a corrective action plan that extends the
23 implementation period beyond 10 years, the participating
24 utility shall include the verification statement in its final
25 annual report. Following the date of a Commission order
26 approving the final annual report or the date on which the

1 final report is deemed accepted by the Commission, the
2 participating utility's annual reporting obligations under
3 this subsection (d) shall terminate, provided, however, that
4 the participating utility shall have a continuing obligation to
5 provide information, upon request, to the Commission regarding
6 the Gas AMI Deployment Plan.

7 (h) If Section 9-244.5 of this Act becomes inoperative with
8 respect to one or more participating utilities as set forth in
9 subsection (g) of that Section, then Sections 9-244.5 and
10 19-150.6 of this Act, other than this Section, shall become
11 inoperative as to each affected participating utility and its
12 service area on the same date as Section 9-244.5.

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