



## 98TH GENERAL ASSEMBLY

### State of Illinois

### 2013 and 2014

#### HB2414

by Rep. Brandon W. Phelps

#### 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 07848 JLS 37932 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 ~~sequestrian~~ 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.