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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF GAS COST ADJUSTMENT TO BE APPLICABLE IN THE MONTHS OF DECEMBER 2009 THROUGH FEBRUARY 2010, PURSUANT TO I.C. § 8-1-2-42	))))))	CAUSE NO. 43629 GCA 12 APPROVED: DEC 0 2 2009

BY THE COMMISSION:
James D. Atterholt, Commissioner
Lorraine Hitz-Bradley, Administrative Law Judge

On September 28, 2009, in accordance with Ind. Code § 8-1-2-42, Northern Indiana Public Service Company ("Petitioner" or "NIPSCO") filed with the Indiana Utility Regulatory Commission ("Commission") its Petition in this Cause for approval of a Gas Cost Adjustment ("GCA") to be applicable during the billing cycles of December 2009 through February 2010. On October 20, 2009, Petitioner pre-filed the direct testimony and supporting exhibits of Katherine A. Cherven, Manager of Compliance, Rates Department; Roger A Huhn, Director of Resource Planning, Energy Supply and Trading; and Mitchell E. Hershberger, Controller. On October 28, 2009, in accordance with I.C. § 8-1-2-42, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its statistical report and the direct testimony and exhibits of Lianne N. Lockhart, a Utility Analyst with the OUCC.

Pursuant to notice, duly published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an evidentiary hearing was held in this Cause on November 2, 2009 at 10:00 a.m. EDT, in Room 224 of the National City Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, *Petitions to Intervene* from the NIPSCO Industrial Group and the City of Hammond were granted. Petitioner presented its evidence without objection, as did the OUCC, although the testimony of Ms. Lockhart was amended from what was prefiled on October 28, 2009. No member of the rate paying public was present at the hearing.

At the November 2, 2009 hearing, the Presiding Officers requested that Petitioner re-file its schedules to reflect the level of unaccounted-for gas that Petitioner experienced in the most recent year. On November 6, 2009, Petitioner filed with the Commission its *Motion to Accept Petitioner's Late-Filed Exhibit 4*, which included the requested revised schedules supported by an affidavit from Katherine Cherven. On November 12, 2009, the City of Hammond filed a notice indicating it had no objections to the revised schedules; the OUCC and NIPSCO Industrial Group similarly advised the Presiding Administrative Law Judge on the same day via e-mail that they had no objections to the revised schedules.

Based upon the applicable law, the evidence presented herein, and being duly advised, the Commission now finds:

1. **Statutory Notice and Commission Jurisdiction.** Due, legal and timely notice of the commencement of the public hearing in this Cause was given and published by the Commission as required by law. Petitioner operates a public gas utility and as such, is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended. The provisions of said Act authorize the Commission to act in this Cause. Therefore, this Commission has jurisdiction over the parties and the subject matter herein.

2. **Petitioner's Characteristics.** Petitioner is a public utility corporation organized and existing under the laws of the State of Indiana, with its principal office located at 801 East 86th Avenue, Merrillville, Indiana. It is engaged in rendering gas distribution service in the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the distribution and furnishing of such service to the public.

3. **Source of Natural Gas.** I.C. § 8-1-2-42(g)(3)(A) requires Petitioner to make every reasonable effort to acquire long-term natural gas supplies in order to provide gas to its retail customers at the lowest gas cost reasonably possible.

Mr. Roger Huhn testified that NIPSCO meets this objective by managing a balanced and fully diversified gas supply portfolio comprised of a variety of commodity, transportation and storage resources. The commodity portfolio is balanced with a combination of fixed-price (physical and financial) and market based purchases. The commodity portfolio diversification is achieved by acquiring gas from a number of suppliers through a competitive bidding process and utilizing a variety of pricing structures sourced from multiple locations. These gas supplies are delivered to NIPSCO through multiple long-term firm transportation arrangements with several different interstate gas pipelines, providing access to multiple supply basins. Mr. Huhn testified that NIPSCO also has several long-term firm contractual storage services as well as on-system storage capability to meet its gas customers' requirements. The storage portfolio is further diversified through a variety of storage service types in multiple locations in the market area, as well as in producing regions.

Mr. Huhn further testified that during the three-month recovery period beginning December 1, 2009, NIPSCO will purchase supply under firm arrangements on both a term and spot market basis. To achieve diversity of supply, he stated that NIPSCO has contracted with several pipelines permitting access to multiple supply basins. NIPSCO has long-term firm transportation contracts with Natural Gas Pipeline Company of America ("Natural"), Panhandle Eastern Pipe Line Company ("Panhandle"), Trunkline Gas Company ("Trunkline"), ANR Pipeline Company ("ANR"), Vector Pipeline ("Vector") and Northern Border Pipeline ("Border"). The long-term, firm, long-haul transportation contracts with Natural, Panhandle, Trunkline, and ANR have an aggregate Maximum Daily Quantity ("MDQ") during the peak season of 458,151 Dth and an off-peak MDQ of 340,174 Dth. Generally speaking, he noted the winter season is defined as the peak season, and the summer season is defined as the off-peak season.

With regard to storage, Mr. Huhn testified that firm storage service contracts with Natural, Panhandle, ANR, Moss Bluff Hub Partners, L.P. ("Moss Bluff"), Kinder Morgan Texas Pipeline, L.P. ("KMTP"), ENSTOR Operating Company ("Katy"), Washington 10 Storage Corporation

("Washington 10") and Egan Hub Partners, L.P. ("Egan") provide an annual storage capability of 31,745,601 Dth, with maximum daily withdrawal capability of 639,083 Dth to meet winter peaks.

The Commission has indicated that Indiana's gas utilities should make reasonable efforts to mitigate gas price volatility. This includes a program that works to mitigate gas price volatility and considers market conditions and the price of natural gas on a current and forward-looking basis. Based on the evidence offered, we find that Petitioner demonstrated that it has and continues to follow a policy of securing natural gas supply at the lowest gas cost reasonably possible in order to meet anticipated customer requirements. Thus, the Commission finds that the requirement of this statutory provision has been fulfilled.

4. **Purchased Gas Cost Rates.** I.C. § 8-1-2-42(g)(3)(B) requires that Petitioner's pipeline suppliers requested or filed, pursuant to the jurisdiction and procedures of a duly constituted regulatory agency, the costs proposed to be included in the GCA factor. The evidence of record indicates that gas costs in this Petition include transportation rates that have been filed by Petitioner's pipeline suppliers in accordance with Federal Energy Regulatory Commission procedures. The Commission reviewed the cost of gas included in the proposed gas cost adjustment charge and finds the costs to be reasonable. Accordingly, the Commission finds that the requirement of this statutory provision has been fulfilled.

5. **Return Earned.** I.C. § 8-1-2-42(g)(3)(C), in effect, prohibits approval of a GCA that results in the Petitioner earning a return in excess of the return authorized by the last Commission proceeding in which Petitioner's basic rates and charges were approved. The most recent proceeding in which Petitioner's basic rates and charges were approved is Cause No. 38380. The Commission's October 26, 1988 Order in that Cause authorized Petitioner to earn a net operating income of $63,182,056. The evidence of record indicates that for the twelve (12) months ending September 30, 2009, Petitioner's actual net operating income was $23,960,790. Therefore, the Commission finds that Petitioner is not earning a return in excess of that authorized in its last proceeding in which basic rates and charges were approved.

6. **Estimation of Purchased Gas Costs.** I.C. § 8-1-2-42(g)(3)(D) requires that Petitioner's estimate of its prospective average gas costs for each future recovery period be reasonable. The Commission has determined that this requires, in part, a comparison of prior estimates with the eventual actual costs. However, as Ms. Cherven explained in her testimony, the months that would ordinarily be reconciled in this GCA 12 - June, July and August - will be reconciled in other GCA proceedings as part of NIPSCO's transition from a monthly GCA filing to a quarterly GCA filing, in accordance with the Commission's August 26, 2009 Order in Cause No. 43629. Specifically, June and July will be reconciled in Cause No. 41338 GCA 11, and final reconciliation for the month of August will take place in Cause No. 43629 GCA13.

The Commission finds that this statutory factor is not relevant for purposes of this transitional GCA filing by NIPSCO.

7. **Reconciliation.** I.C. § 8-1-2-42(g)(3)(D) also requires that Petitioner reconcile its estimation for a previous recovery period with the actual purchased gas cost for that period. As described in Cause No. 43629, while this filing contains the Schedule 12B with variances from prior

monthly GCA filings which are included in the calculation of the GCA factors, there are no additional months of reconciliation included in this GCA 12. The reconciliation months that are usually included in this quarter are June, July and August. As indicated above, final approval of the June and July reconciliations will take place in Cause No. 41338 GCA 11, and final approval of the August reconciliation will take place in 43629 GCA 13.

The variance from prior recovery periods applicable to the current recovery months of December 2009, January 2010 and February 2010 is an over-collection of $30,232,035, $37,891,161 and $32,982,852, respectively.

Based upon the evidence presented, the Commission finds that Petitioner's proposed GCA properly reconciles the difference between the actual costs for the Reconciliation Period, and the gas costs recovered during that same period.

8. **Adjustment to Reflect Recent Unaccounted-for Gas.** On October 21, 2009, the Commission issued a final Order in Cause No. 41338 GCA 10, which addressed NIPSCO's annual demand cost filing, and reconciliation of commodity costs over the prior twelve months. In that Order, the Commission determined that Petitioner should compute the actual level of unaccounted-for gas on an annual basis, and not on a four-year rolling average basis as had been requested by NIPSCO. In her testimony in this GCA 12, Ms. Cherven indicated that in preparing gas cost estimates for the GCA factors proposed in GCA 12, NIPSCO used a four-year average, as was proposed in GCA 10. Pursuant to the request of the presiding officers, NIPSCO submitted revised schedules that were computed based upon the level of unaccounted-for gas during the most recent year, which was 1.04%. No party expressed opposition to the use of those revised schedules. The Commission therefore finds that the revised schedules submitted by Petitioner on November 6, 2009 should form the basis for the gas cost adjustment factors to be approved herein.

9. **Resulting Gas Cost Adjustment Factor.** The estimated net commodity cost of gas to be recovered during the application periods of December 2009, January 2010 and February 2010 are $53,239,955, $52,687,041 and $51,519,705, respectively. Adjusting this total for the commodity variance and refunds, yields gas costs to be recovered through the GCA and Base Rates of $56,340,653. After dividing that amount by estimated sales, adding the demand costs, subtracting the base cost of gas, and adjusting for Indiana Utility Receipts Tax, Petitioner's recommended GCA factors are:

Estimated GCA per Therm

Rate Class	December 2009	January 2010	February 2010
Residential (Class 1)	($0.0845)	($0.1708)	($0.1159)
General & Interruptible (Class 2 & 3)	$0.0010	($0.0737)	($0.0257)
CNG (Class 4)	$0.3189	$0.3623	$0.3681

10. **Effects on Residential Customers.** The GCA factor of $(0.0845)/Dth represents an increase of $0.0717/Dth from the current GCA factor of $(0.1562)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 1:

Table 1 Proposed GCA Factor for December 2009 vs. Currently Approved GCA Factor for October 2009				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor ($0.0845)**	**Bill at Currently Approved GCA Factor ($0.1562)**	**Dollar Change**	**Percent Change**
5	$27.42	$23.83	$3.59	15.07%
10	$48.47	$41.30	$7.17	17.36%
15	$69.53	$58.77	$10.76	18.31%
20	$90.58	$76.24	$14.34	18.81%
25	$119.39	$101.47	$17.92	17.66%

The GCA factor of $(0.1708)/Dth represents a decrease of $0.0146/Dth from the current GCA factor of $(0.1562)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 2:

Table 2 Proposed GCA Factor for January 2010 vs. Currently Approved GCA Factor for October 2009				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor ($0.1708)**	**Bill at Currently Approved GCA Factor ($0.1562)**	**Dollar Change**	**Percent Change**
5	$23.10	$23.83	($0.73)	(3.06)%
10	$39.84	$41.30	($1.46)	(3.54)%
15	$56.58	$58.77	($2.19)	(3.73)%
20	$73.32	$76.24	($2.92)	(3.83)%
25	$97.82	$101.47	($3.65)	(3.60)%

The GCA factor of $(0.1159)/Dth represents an increase of $0.0403/Dth from the current GCA factor of $(0.1562)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 3:

Table 3 Proposed GCA Factor for February 2010 vs. Currently Approved GCA Factor for October 2009				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor (\$0.1159)**	**Bill at Currently Approved GCA Factor (\$0.1562)**	**Dollar Change**	**Percent Change**
5	\$25.85	\$23.83	\$2.02	8.48%
10	\$45.33	\$41.30	\$4.03	9.76%
15	\$64.82	\$58.77	\$6.05	10.29%
20	\$84.30	\$76.24	\$8.06	10.57%
25	\$111.54	\$101.47	\$10.07	9.92%

The GCA factor of \$(0.0845)/Dth represents a decrease of \$0.8446/Dth from the GCA factor billed one year ago of \$0.7601/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 4:

Table 4 Proposed GCA Factor for December 2009 vs. GCA Factor Prior Year for December 2008				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor (\$0.0845)**	**Bill at Prior Year Approved GCA Factor \$0.7601**	**Dollar Change**	**Percent Change**
5	\$27.42	\$69.81	(\$42.39)	(60.72)%
10	\$48.47	\$133.25	(\$84.78)	(63.62)%
15	\$69.53	\$196.70	(\$127.17)	(64.65)%
20	\$90.58	\$260.14	(\$169.56)	(65.18)%
25	\$119.39	\$331.34	(\$211.95)	(63.97)%

The GCA factor of \$(0.1708)/Dth represents a decrease of \$0.9012/Dth from the GCA factor billed one year ago of \$0.7304/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 5:

Table 5 **Proposed GCA Factor for January 2010** **vs.** **GCA Factor Prior Year for January 2009**				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor ($0.1708)**	**Bill at Prior Year Approved GCA Factor $0.7304**	**Dollar Change**	**Percent Change**
5	$23.10	$68.32	($45.22)	(66.19)%
10	$39.84	$130.28	($90.44)	(69.42)%
15	$56.58	$192.24	($135.66)	(70.57)%
20	$73.32	$254.20	($180.88)	(71.16)%
25	$97.82	$323.92	($226.10)	(69.80)%

The GCA factor of $(0.1159)/Dth represents a decrease of $0.7501/Dth from the GCA factor billed one year ago of $0.6342/Dth. The effects of this change for various consumption levels of residential customer bills are shown in table 6:

Table 6 **Proposed GCA Factor for February 2010** **vs.** **GCA Factor Prior Year for February 2009**				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor ($0.1159)**	**Bill at Prior Year Approved GCA Factor $0.6342**	**Dollar Change**	**Percent Change**
5	$25.85	$63.51	($37.66)	(59.30)%
10	$45.33	$120.66	($75.33)	(62.43)%
15	$64.82	$177.81	($112.99)	(63.55)%
20	$84.30	$234.96	($150.66)	(64.12)%
25	$111.54	$299.86	($188.32)	(62.80)%

11. **Interim Rates.** The Commission is unable to determine whether Petitioner will earn an excess return while this GCA is in effect. Accordingly, the Commission has authorized that the approved rates herein should be interim rates subject to refund pending reconciliation in the event an excess return is earned.

12. **Monthly Flex Mechanism**. Petitioner has proposed using a flex mechanism each month to adjust the GCA for the subsequent month, consistent with the practices of other Indiana gas utilities and the Commission's August 26, 2009 Order in Cause No. 43629. The flex will apply only to estimated pricing of estimated market purchases ("the initial market price") in the GCA. The flex will be filed no less than three (3) days before the beginning of each calendar month during the GCA quarter. Changes in the market price included in the flex will be limited to a maximum adjustment (up or down) of $1.00 from the initial market price.

This Commission has indicated in prior orders that Indiana's gas utilities should make reasonable efforts to mitigate gas price volatility. Petitioner's proposal for a month flexing mechanism is designed to address this Commission's concerns. In addition, the Commission authorized this mechanism for other gas utilities. Therefore, it is reasonable to authorize Petitioner to initiate a monthly flex mechanism in the manner it has here proposed.

IT IS, THEREFORE, ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Petition of Northern Indiana Public Service Company for the gas cost adjustment for natural gas service, as set forth in Finding Paragraph No. 9, is hereby approved, subject to refund in accordance with Finding Paragraph No. 11.

2. Petitioner shall file with the Natural Gas Division of the Commission the gas cost adjustments herein approved, separate amendments to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

3. This Order shall be effective for the billing cycles of December 2009 through February 2010.

ATTERHOLT, GOLC, AND LANDIS CONCUR; HARDY AND ZIEGNER ABSENT:

APPROVED: DEC 0 2 2009

I hereby certify that the above is a true and correct copy of the order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission