ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF ANNUAL DEMAND, TAKE-OR-PAY, TRANSITION AND STORAGE AND TRANSMISSION COSTS TO BE APPLICABLE IN THE TWELVE-MONTH PERIOD, BEGINNING NOVEMBER 1, 2008	)))))))	CAUSE NO. 41338 GCA 10 APPROVED: OCT 21 2009

JL6

BY THE COMMISSION:
Larry S. Landis, Commissioner
Lorraine Hitz-Bradley, Administrative Law Judge

On August 27, 2008, in accordance with the Commission's August 11, 1999 Order in Cause No. 41338, Northern Indiana Public Service Company ("Petitioner"), filed its verified Petition in this Cause for approval of the annual demand, storage and transmission cost of Petitioner's rates, to be applicable during the twelve-month period beginning November 1, 2008. The Petition also requested the creation of a subdocket to address unaccounted for gas ("UAFG") issues. As noted below, Petitioner subsequently withdrew its request for a subdocket.

Petitions to Intervene were filed by the Board of Commissioners of LaPorte County, Indiana ("LaPorte County") and Mittal Steel USA, Praxair, Inc., and U.S. Steel Corporation (collectively called "NIPSCO Industrial Group") on September 8 and 9, 2008, respectively. The Presiding Officers granted these petitions to intervene in a September 17, 2008 Docket Entry.

Pursuant to notice published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a Prehearing Conference and Preliminary Hearing was held in this Cause on October 6, 2008 at 9:30 A.M. EST at the Commission's office in Room 224 of the National City Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner, the Indiana Office of Utility Consumer Counselor ("OUCC"), LaPorte County and NIPSCO Industrial Group participated in the prehearing conference and a procedural schedule was agreed to by the parties. Based on the parties' agreement to a lengthened procedural schedule, Petitioner withdrew its request for the creation of a subdocket for the purpose of addressing UAFG issues. The Commission issued a Prehearing Conference Order on October 15, 2008.

Petitioner filed a motion on October 30, 2008 requesting a preliminary finding that Petitioner's Exhibit 1D was confidential, proprietary, and/or trade secret information that should be exempt from public disclosure and for the establishment of procedures to protect that information. The Presiding Officers' November 6, 2008 Docket Entry made a preliminary finding that the information should be exempt from public disclosure to allow the information to be reviewed under seal. As noted below, we now make a permanent finding that the identified information is confidential.

On October 31, 2008, Petitioner filed its *Unopposed Motion to Make Rates Effective Subject to Refund* ("Motion"). In its *Motion*, Petitioner proposed that the rates as contained in its Petition be made effective, on an interim basis, subject to refund. The *Motion* also stated that the OUCC, the NIPSCO Industrial Group, and LaPorte County did not object to the *Motion*. Our November 20, 2008 Interim Order in this Cause granted the *Motion* thereby placing Petitioner's proposed GCA factors in place on an interim basis subject to refund.

The OUCC filed a *Motion to Dismiss the Unaccounted-For-Gas Issue* on February 9, 2009. Petitioner, LaPorte County and the NIPSCO Industrial Group filed a response on February 19, 2009 and the OUCC filed a reply on February 26, 2009. We took the OUCC's *Motion to Dismiss* under advisement and will address the *Motion* in this Order.

Petitioner filed its case-in-chief consisting of the testimony of Katherine A. Cherven and Karl E. Stanley on August 27, 2008. Pursuant to the Prehearing Conference Order and the November 21, 2008 Docket Entry granting Petitioner's request for an extension of time to file additional testimony, Petitioner filed the Supplemental Direct Testimony of Michael J. Martin on November 24, 2008. On March 6, 2009, the OUCC submitted the testimony of Jerome D. Mierzwa and the NIPSCO Industrial Group submitted the testimony of Nicholas Phillips, Jr. The OUCC filed cross answering testimony from Mr. Mierzwa on March 27, 2009. Petitioner also filed rebuttal testimony of Mr. Martin, Mr. Stanley and Ms. Cherven on March 27, 2009.

Pursuant to notice published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, evidentiary hearings were held in this Cause on April 20 and 21, 2009 at 10:30 a.m. EST in Room 224 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. Petitioner, the NIPSCO Industrial Group, LaPorte County and the OUCC appeared at the hearing and presented testimony or exhibits. No member of the rate paying public appeared at the hearings or otherwise sought to testify. Based upon the applicable law and evidence presented herein, the Commission now finds:

1. **Notice and Jurisdiction**. Petitioner owns and operates a public utility which is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended.

In Cause No. 41338, the Commission's August 11, 1999 Order approved a proposed redesigned mechanism consisting of two parts: a monthly commodity filing and an annual demand charge filing. Under this mechanism, Petitioner has been making a monthly commodity filing to determine the gas commodity component of the GCA factor for a calendar month with twelve monthly filings being made each year. Petitioner began making these monthly commodity filings on September 1, 1999. Also, under the redesigned GCA mechanism as approved by the Commission, Petitioner is required to make an annual filing three working days prior to September 1 of each year to determine the demand component of its gas costs for the twelve months to be effective on November 1 of the year in which the annual filing is made. Petitioner's August 27, 2008 Petition represents the tenth annual filing pursuant to the redesigned GCA mechanism as approved by the August 11, 1999 Order. This Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Petitioner's Characteristics**. Petitioner is engaged in rendering natural gas utility service to the public within the State of Indiana and owns, operates, manages and controls plant and equipment used for distribution and furnishing such service.

3. **Issues to be Addressed**. Petitioner requests approval of the annual demand, storage and transmission cost of Petitioner's rates, to be applicable during the twelve-month period beginning November 1, 2008. Petitioner further requested approval of a new mechanism for the recovery of UAFG costs.

Both the OUCC and the NIPSCO Industrial Group presented evidence on Petitioner's proposed mechanism for recovering UAFG. In addition, the OUCC expressed concerns with Petitioner's capacity reserve allowance and Petitioner's pricing of storage gas. We address all of these matters below.

4. **UAFG.** Petitioner requested the approval of a mechanism to reconcile, recover and allocate the cost of UAFG that occurs on its system between Petitioner and its ratepayers. Evidence was presented on this issue by Petitioner, the OUCC and the Industrial Group. The OUCC also filed a *Motion to Dismiss* Petitioner's request for approval of the UAFG mechanism. We address below the evidence on this issue, as well as the OUCC's *Motion to Dismiss*.

a. **Petitioner's UAFG Proposal**. Ms. Cherven, Petitioner's Manager of Compliance in the Rates Department, described a modification to Petitioner's accounting for unbilled revenue that began in March 2008. She indicated that an internal analysis revealed Petitioner's existing method for determining monthly unbilled revenue was resulting in amounts that were larger than they should have been, necessitating a change in the unbilled revenue methodology to generate more accurate amounts. Ms. Cherven stated that this change impacts the monthly level of UAFG, which is inter-related to the unbilled revenue methodology. Ms. Cherven testified that the cycle billing process used by Petitioner leads to variances between gas volumes that are delivered by suppliers and those volumes that are metered and recorded as sold at the customer premises. She noted that unbilled revenue accounts for some of the variance but that Petitioner's UAFG accounts for the remainder of the variance. Ms. Cherven stated that a change in the unbilled revenue calculation implicitly affects UAFG. She noted that purchased gas costs related to actual UAFG levels are credited against purchased gas costs monthly because Petitioner was permitted an allowance for UAFG in its current base rates.

Ms. Cherven stated that for the past several years, Petitioner has used a UAFG level of 0.15%. As part of its analysis of the unbilled revenue methodology change, Petitioner examined its UAFG levels over a full twelve months of experience. Ms. Cherven explained that Petitioner reviewed the monthly and annual variance between send-out and metered gas sales data net of unbilled revenue for the previous four years to determine the amount of UAFG actually occurring on its system. She explained that on a preliminary basis, the UAFG for the twelve month periods ended

July 31 during the years 2005-2008 was 0.99%.[1]

Mr. Martin, Director, Regulatory and Government Policy for NiSource Corporate Services Company[2], also addressed Petitioner's proposed change in its UAFG. Mr. Martin testified that UAFG and unbilled revenue are inter-related for the reasons described by Ms. Cherven. Mr. Martin asserted that the new methodology for calculating unbilled revenue is an improvement because it is expected to provide more accurate unbilled revenue amounts. Mr. Martin stated that Petitioner had reviewed data from the past four years and determined the variance resulting from the difference between the gas brought into its system by suppliers vs. the amount metered at its customers' premises results in an average level of UAFG of approximately 0.62%. Petitioner's past annual GCA filings have reflected a UAFG of 0.15%.

Mr. Martin attached schedules to his testimony showing the historical analysis of Petitioner's UAFG level and explained that the lower level reflected in his testimony (as compared to Ms. Cherven's) was due to the realization that gas used in generation stations, delivered by Petitioner, but purchased from a 3rd party supplier, had not been properly accounted for in the preliminary analysis and that an adjustment for linepack was improperly incorporated as a deduction rather than an addition.

Mr. Martin explained that historically, Petitioner and most other gas utilities had a system-wide UAFG level determined in a base rate proceeding that is built into the utility's base rates. He noted that for Petitioner, the amount determined in its last base rate case decided in 1988, Cause No. 38380, was $3.0 million and was based on a system wide UAFG of 0.85%. Mr. Martin stated that Petitioner deducts from its GCA filings the actual cost of purchased gas attributable to UAFG so that there is no double recovery of UAFG costs.

Mr. Martin asserted that given the volatility of gas prices in recent years, it is no longer appropriate to continue to recover the cost of UAFG as a fixed cost that was established in a 1988 base rate proceeding. Mr. Martin stated that volatility in gas prices alone could either hurt or harm the utility and its ratepayers and urged adoption of a mechanism that allows the utility to recover the cost of UAFG in a manner that recognizes the fluctuations in natural gas prices. Mr. Martin acknowledged that Petitioner does exercise some control over the magnitude or level of the UAFG it experiences through good business practices. He noted that Petitioner had reduced its level of UAFG by replacing its older metallic based pipe with plastic pipe since the 0.85% UAFG level was established in the last rate case. However, he said Petitioner cannot control the price at which it acquires the gas. Mr. Martin testified that a majority of states permit recovery of UAFG for their regulated gas utilities through their Commission approved gas cost recovery mechanisms. However, during cross examination, Mr. Martin could not recall to which states he was referring in his testimony. He also did not know whether any of the approved UAFG recovery mechanisms were a result of some action that had been taken in those gas utilities' base rate cases. Tr. at A-62.

---

[1] This amount was subsequently revised to 0.62% and explained in the Supplemental direct testimony of Michael J. Martin.

[2] Mr. Martin revised his testimony on the record during the April 20, 2009 evidentiary hearing to reflect that effective January 1, 2009 he was employed by NIPSCO.

Mr. Martin testified that it is appropriate for an Indiana utility to be allowed to recover changing UAFG costs through the GCA. He indicated that the increase in natural gas prices is outside the control of utilities. He stated the establishment of a new fixed cost for UAFG in a base rate case would quickly become out of date, due to the volatility of gas prices, to the detriment of the utility or the ratepayer depending on the amount fixed in the base rate case. Mr. Martin also believes that UAFG is a gas cost and is eligible for recovery through the GCA mechanism, with Commission approval.

Mr. Martin acknowledged the 1983 Generic Order concluded that the recoverability of a "specific amount of" UAFG is best retained in the broad based inquiry of a general rate case. He noted that Petitioner is proposing only to change the cost associated with the rate-base-established UAFG magnitude. Mr. Martin noted that the Commission had recently approved mechanisms that allow recovery of floating UAFG costs through the GCA mechanism for Vectren North, Vectren South and Citizens Gas.

Mr. Martin described Petitioner's proposal for recovery of UAFG costs. He explained that Petitioner requested that it be permitted to recover the actual cost of gas related to its UAFG up to the percentage that was established in its rate case, 0.85%. Thus, Petitioner would be authorized to recover only UAFG dollars that are in excess of the $3 million on UAFG that is less than .85%. Mr. Martin said that by using this mechanism, Petitioner would continue to limit its recovery of UAFG to the level that was set in its rate case. Petitioner would not attempt to change that percentage until a subsequent case. Mr. Martin stated this change would not result in Petitioner earning more than its authorized return based on Petitioner's earnings history since its last rate case.

Mr. Martin explained the mechanics he recommended for calculating the historic average percentage of UAFG. He believed that a minimum period of time that should be used to determine the UAFG percentage occurring on its system is a 48 month or four- year time period. Mr. Martin stated that over a four -year period of time any abnormalities could be eliminated, such as the impact of weather, unusual impact due to load growth that could affect the seasonality of billing, and any impacts of balancing that occurs on the system that may be unusual. The Company would propose that the four- year average be determined on a rolling basis for each forty-eight month period that would end in July. After determining that percentage, the Company would compare the amount determined to the amount that was permitted in its base rate case of 0.85%. If the four-year average of UAFG is less than 0.85%, then a full level of UAFG gas costs would be recoverable in the GCA for a subsequent twelve month period less $3.0 million. If the four-year average percentage was greater than 0.85%, the Company would only be permitted to recover UAFG gas costs on an amount computed at 0.85%. Any amount of UAFG gas costs greater than 0.85% would be credited and refunded back to its customers.

Mr. Martin stated that if actual purchased gas costs were greater or less than the amount projected for the month in question, Petitioner would reconcile the actual gas cost but limit the UAFG recovery to the computed four-year average less a proportionate monthly share of the $3.0 million recovered in base rates. Because of the factors described earlier in testimony, including the impact of cycle billing, Petitioner does not recommend using the actual UAFG percentage experienced monthly in the reconciliation process. However, at the end of the twelve month period ended July, Petitioner would reconcile the actual cost of UAFG experienced during the twelve month period.

b. OUCC's Evidence on UAFG Proposal. Mr. Mierzwa, a Principal and a Vice President of Exeter Associations, Inc., addressed NIPSCO's proposal to modify the recovery procedures for UAFG costs in this annual GCA proceeding.

Mr. Mierzwa testified that NIPSCO's last base rate case utilized a test year ended June 30, 1987. In that case, the Commission's Final Order permitted the Company to recover $3.0 million as a base rate operating expense for unaccounted-for gas ("UAFG"). Mr. Mierzwa testified that his allowance was based on a system-wide UAFG rate of 0.85%. He stated that in its 2008 annual GCA filing, NIPSCO proposes to implement a mechanism similar to those recently adopted in the Vectren Utilities and Citizens Gas proceedings for the recovery of UAFG costs. Under NIPSCO's proposal, UAFG costs in excess of $3.0 million may be recovered through the GCA. The total UAFG costs recoverable under NIPSCO's proposal would not be limited to those associated with the $3.0 million UAFG allowance utilized in NIPSCO's last base rate case. Rather, NIPSCO would be allowed to recover up to 0.85% of gas costs for the UAFG.

Mr. Mierzwa argued that NIPSCO's proposal for recovery of UAFG costs should not be considered in this proceeding. As explained in the OUCC's *Motion to Dismiss Unaccounted-For Gas Issue* filed on February 9, 2009, and the *OUCC's Reply to NIPSCO's and NIPSCO Industrial Group's Responses* filed on February 26, 2009, the recovery of unaccounted-for gas costs is best reviewed in a general base rate proceeding. He argued that it is improper single-issue ratemaking to isolate one rate case expense for consideration (UAFG costs) as NIPSCO has proposed, without considering changes in the other costs of providing service. While the costs for UAFG may be higher than in the last rate case, other costs such as balancing, compressor fuel, and/or storage losses may be lower. For example, the compressor fuel costs included in NIPSCO's last base rate case totaled $1,104,195. These costs have averaged $424,045 per year over the last 4 years. *See* Public's Exhibit No. 2, pages 5-6, NIPSCO Responses to Q-13 and Q-14. Mr. Mierzwa stated that the costs of providing service to all customers in the NIPSCO territory need to be examined before base rate types of charges, including the UAFG component, are changed.

Mr. Mierzwa testified that NIPSCO did not accurately reflect UAFG costs in its GCA 10 filings. He stated that NIPSCO witness Martin testified that NIPSCO utilized a UAFG factor of 0.15% in prior annual GCA filings, including its GCA 10 filing, but a recent analysis has determined that NIPSCO's actual UAFG experience during the GCA 10 period was 0.73%. *See* NIPSCO Exhibit 3, Attachment B, Column Aug 2007 – July 2008, line 14. Mr. Mierzwa stated that the difference between these two percentages caused the amount deducted from gas costs for UAFG to be understated during the GCA 10 period. The amount of that understatement, as calculated by Mr. Mierzwa, is $4,087,418, and he recommended that the GCA 10 gas costs be reduced by that amount. Mr. Mierzwa testified that if NIPSCO's actual UAFG percentage for that period was based on 1.20% (NIPSCO's actual experience) instead of the .15% (the UAFG factor reported in NIPSCO's monthly filings), the amount to be refunded would instead be $7,399,574, rather than the $4,087,418 calculated.

Mr. Mierzwa challenged Petitioner's proposal to use a four year rolling average UAFG for purposes of calculating its UAFG cost to be deducted from gas costs. He indicated that 0.73% for the most recent year would be a more appropriate UAFG percentage because it reflected only current UAFG. Mr. Mierzwa also questioned whether Petitioner had properly estimated its 0.62% four year average UAFG level, but acknowledged on cross-examination that he had been provided additional data that satisfied his concern that Petitioner had properly calculated UAFG for the four-year period.

c. **Industrial Group's Evidence on UAFG Proposal**. Mr. Phillips, a consultant with Brubaker & Associates, Inc., testified on behalf of the Industrial Group. Mr. Brubaker testified that Petitioner's transportation customers provide more than Petitioner's actual UAFG cost, as a function of applying the 0.85% UAFG from the last rate case rather than the actual UAFG. Mr. Phillips stated that transportation customers buy gas at their own expense and risk, and pay Petitioner to have their gas delivered from gas-producing states to Petitioner's gas system and deliver the gas to the customer's premise through Petitioner's distribution system. He stated that Petitioner requires transportation customers to provide a 0.85% line loss deduction to compensate Petitioner for UAFG. These additional quantities are intended to hold Petitioner harmless and replace claimed line losses associated with the delivery of gas. Mr. Phillips concluded that Mr. Martin's analysis showed that transportation customers have been providing Petitioner with excess replacement gas over at least a four year period and that Petitioner should lower its UAFG percentage for transportation customers to reflect actual UAFG. Mr. Phillips believed that an additional reason to lower the UAFG rate applicable to transportation customers is that they are served by high pressure service lines with lower line losses. Mr. Phillips concurred on cross-examination that a change in Petitioner's tariff would be necessary to implement this change.

d. **OUCC Cross-Answering Evidence**. Mr. Mierzwa disagreed with Mr. Phillips that the UAFG level for transportation customers should be reduced to Petitioner's four year average UAFG as calculated by Mr. Martin. Mr. Mierzwa testified that UAFG is currently recovered through NIPSCO's base rates at the level allowed by the Commission in NIPSCO's last base rate case. As further explained at pages 1-2 of the *OUCC's Reply to NIPSCO's and NIPSCO Industrial Group's Responses* ("OUCC's Reply"), the Commission has found that the appropriate level of UAFG is more properly determined in a general base rate proceeding. Therefore, the UAFG assessed to transportation customers should be established in a base rate proceeding, not this GCA proceeding.

Mr. Mierzwa testified the 0.62% UAFG experience identified by witness Martin reflects only the difference between the quantity of gas received by NIPSCO, which is available for sale, and the quantity of gas actually sold. The UAFG charge assessed to transportation customers is more commonly referred to as a fuel retention, or retainage, charge. It is common in the natural gas industry for retainage charges to also recover gas used in company operations. As noted at page 2 of the OUCC's Reply, the Commission's August 3, 1983 Order in Cause No. 37091 ("August 3 Order"), indicated that UAFG has many causes, including gas used for the utility's own purposes. Mr. Mierzwa stated that there are no records available which indicate whether the 0.85% UAFG charge established in NIPSCO's last base rate case proceeding included company-use gas.

Finally, Mr. Mierzwa argued that if the Commission were to address UAFG in this proceeding, equity dictates that charges to transportation customers which affect the gas costs charged to GCA customers should also be examined. For example, Mr. Mierzwa stated that NIPSCO incurs costs to balance differences between the gas supply deliveries and requirements of transportation customers. Based on the NIPSCO Industrial Group's response to OUCC DR1-Q-3, Mr. Mierzwa understands that the charges currently assessed to transportation customers for balancing services were established in the 1990s. Mr. Mierzwa asserted that the balancing service requirements and the costs associated with providing this service are likely to have changed since then. Mr. Mierzwa testified that a general base rate proceeding is the appropriate venue to review all charges to transportation customers.

e. Petitioner's Rebuttal on UAFG Proposal. Mr. Martin disagreed with Mr. Mierzwa that UAFG adjustments should be considered only in a base rate proceeding. He reiterated that the primary factor that contributes to UAFG costs is the cost of purchased gas incurred by Petitioner to serve its sales customers, which costs are routinely recovered, reviewed and approved by the Commission in the GCA mechanism. He stated that purchased gas costs are volatile and beyond the control of the utility. Mr. Martin testified that the commodity cost of gas has been as high as $12 per Dth and is now below $4.00 per Dth. He believed that this range of price volatility would make it very difficult for any gas utility, at the current time, to appropriately and fairly value the cost of UAFG in a base rate case. In order to ensure that customers pay no more and no less than the prudently incurred cost of gas, he recommended treating the cost associated with UAFG as a GCA cost. Mr. Martin believed that only the volume of UAFG, stated as a percentage, should be evaluated and decided in a base rate proceeding.

Mr. Martin also disputed Mr. Mierzwa's assertion that the actual UAFG factor to be used in this proceeding be established at 0.73%. He reiterated the explanation included in his direct testimony that the best mechanism to establish UAFG was a four-year average. He stated that Petitioner's calculation of the four-year average, based on actual volumes delivered into the Company's system and throughput as metered at customers' premises, is 0.62% for the four-year period ending July 2008.

Mr. Martin disagreed with Mr. Mierzwa's assertion that Petitioner should return $4.1 million to its customers for UAFG. Mr. Martin said that Petitioner deducts its actual costs of UAFG in the GCA to prevent a double collection from its customers because such costs are currently recovered in its base rates. He stated that Petitioner has consistently reduced the gas costs recovered in the past ten GCAs based on the reduced UAFG. On cross-examination, Mr. Martin testified that Petitioner believed that 0.15% was the appropriate percentage for UAFG until a new analysis showed otherwise. Tr. at C-64. The Company began using the higher UAFG factor of 0.62% in August 2008 "after it determined this new level of UAFG". Martin Rebuttal, p. 6. Referring to the change in the UAFG percentage, Mr. Martin stated that "[t]o the extent that it was included in [NIPSCO's] filings, it was likely deemed as approved unless it was opposed in some way by the Commission." Tr. At C-66. Mr. Martin testified that he didn't believe that NIPSCO asked to modify the UAFG percentage, but he also didn't feel that NIPSCO had a "need" to do that. *Id.* Mr. Martin stated that all monthly GCA filings since August 2008 have utilized this new increased UAFG factor.

Mr. Martin disagreed with Mr. Mierzwa's suggestion that Petitioner's UAFG costs should be recalculated for the GCA 10 period (August 2007 through July 2008). Mr. Martin stated on cross-examination that NIPSCO used a .15 UAFG factor in this GCA and had "deducted what [NIPSCO] understood to be the unaccounted for gas for that period of time." Tr. at C-78. Mr. Martin also testified when questioned by the bench that more money would be returned to ratepayers if NIPSCO used the recommended .62 UAFG percentage than if NIPSCO used the .15%; similarly, more would be returned to ratepayers at the authorized .85 UAFG percentage rather than NIPSCO's requested .62%. Tr. at C-114. Petitioner submits that the change in UAFG factor should be applied prospectively from the time the new factor was determined. Mr. Martin also addressed Mr. Phillips' statement that there has been a "permanent reduction in lost gas" as result of Petitioner's Gas Distribution Improvement Program. He acknowledged that while the replacement of cast iron and bare steel pipe with plastic pipe should reduce the volume of UAFG experienced in the particular distribution lines, he testified that it was inaccurate to describe such an improvement as a "permanent" reduction in the system-wide UAFG. Mr. Martin explained that as each day passes, Petitioner's system ages, and it is natural to assume that UAFG may actually increase, based on the resulting increase in the average age of its system.

Mr. Martin also indicated that Petitioner cannot support Mr. Phillips' statement that the line losses for industrial customers served off high pressure transmission lines are expected to be less than customers served off distribution systems, because Petitioner does not separately meter gas off the high pressure lines as it moves within Petitioner's system. He stated that the installation of plastic pipe primarily serves residential customers, and thus it is reasonable to assume that the greatest improvement in the reduction of UAFG would have been experienced by that customer class, although this cannot be stated with certainty.

Mr. Martin disagreed with Mr. Phillips' assertion that Petitioner would profit from UAFG if it were allowed to recover its actual costs from retail customers and have transportation customers deliver gas in excess of Petitioner's actual losses. Mr. Martin stated that it is GCA customers who benefit when Petitioner retains transportation customers' gas for anticipated losses in excess of the actual UAFG, because retained gas becomes a part of Petitioner's overall gas supply and is used in the determination of the GCA. Mr. Martin stated that if Petitioner retained a lower percentage of transportation customer gas, Petitioner would need to go out and purchase gas for the GCA, thus increasing GCA costs.

Mr. Martin testified that more study is needed before Petitioner could accept Mr. Phillips' contention that the percentage of customer-owned gas delivered by transportation customers should be lowered, or the difference credited to transportation customers. He stated that NIPSCO is not fundamentally opposed to filing tariffs to update the transportation customers' retainage percentage on a periodic basis. After further study, Mr. Martin indicated the Company may decide that it is not opposed to changing the retainage percentage in the respective transportation tariffs to be consistent with the new UAFG calculation and recovery mechanism proposed in this proceeding.

Ms. Cherven responded to Mr. Phillips' assertions that Petitioner would profit from UAFG if it were allowed to recover its actual costs from retail customers and require transportation customers to deliver gas in excess of Petitioner's actual losses. She said that if there are any transport customer volumes delivered in excess of the actual losses, these volumes would be consumed by the retail customers, and would not fall into the unaccounted-for volumes. Ms. Cherven stated that during the reconciliation process, the volumes consumed are multiplied by the base cost of gas plus the gas cost adjustment rate to determine the gas costs recovered. Ms. Cherven testified these recovered gas costs are compared to the actual gas costs to determine if there is an under-collection or over-collection of gas costs. Any variance is passed on to the retail customer. She concluded that if excess volumes were to be delivered by the transportation customers, the retail customer would receive those volumes and they would be included in the recovered gas cost calculation and would not become a profit to Petitioner. She also said that the UAFG gas costs are a percentage of the actual gas costs incurred and Petitioner is proposing recovery of this actual gas cost.

f. OUCC's *Motion to Dismiss Petitioner's UAFG Request*. The OUCC filed a *Motion* requesting the Commission dismiss Petitioner's UAFG proposal (the "*Motion*"). The *Motion* quoted language in the 1983 Generic Order providing that "[w]hether a specific amount of UAFG is reasonable and should therefore be recovered from a utility's ratepayers is an extremely fact sensitive determination which, we believe is best retained in the broad based inquiry of a general rate proceeding." The OUCC asserted that it was inappropriate to isolate one rate case expense for examination without considering the remainder of Petitioner's revenue requirements, given that twenty years have passed since NIPSCO's last rate case.

The OUCC also noted that the Commission orders for Vectren South, Vectren North and Citizens Gas that allowed UAFG costs to be recovered through GCA mechanisms were approved in the context of a base rate change. The OUCC noted this was consistent with the Commission's continuing preference to review UAFG costs in the framework of an Indiana gas utility's general base rate case.

Petitioner, the NIPSCO Industrial Group, and LaPorte County responded to the *Motion*. Petitioner stated that I.C. § 8-1-2-42(a) and (g) give the Commission the authority to approve purchased gas tracking mechanisms. Petitioner contended it is beyond dispute that UAFG is a gas cost, as the Commission so found in its 1983 Generic Order. Petitioner urged the Commission to deny the *Motion* and hear evidence on Petitioner's proposal.

Petitioner also contended that language in the 1983 Generic Order requiring the UAFG "amount" to be established in a base rate case related to the establishment of a baseline "volume" of UAFG. Petitioner agreed that establishing a baseline volume was a fact-sensitive determination best made in a base rate proceeding. However, it contended the cost associated with the volume of UAFG can routinely be determined in a GCA proceeding.

Petitioner did not dispute that the UAFG procedures adopted for Vectren North, Vectren South and Citizens all arose out of a rate case. However, it argued that there was no compelling logic suggesting the cost of UAFG should be established in a base rate case. Petitioner also noted that increasing volatility, which was not present at the time the 1983 Generic Order was issued, renders establishment of fixed UAFG costs in a base rate proceeding speculative. Petitioner urged the Commission to review the evidence to evaluate the reasons its proposal was more consistent with the market volatility now faced by gas utilities. Petitioner also disagreed that its proposed procedure for

UAFG costs represented single-issue ratemaking. Petitioner argued that UAFG is a purchased gas cost over which Petitioner has very little control. Petitioner asserted that re-setting other costs in a base rate case will have no impact on the fact that UAFG costs will continue to vary.

The NIPSCO Industrial Group also opposed the *Motion*, noting that transportation customers deliver 0.85% more gas than their nomination for UAFG and would benefit from a lower UAFG percentage. Because Petitioner is under a rate case moratorium precluding it from filing a base rate case that had rates effective prior to May 2010, no adjustment to the UAFG level imposed on transportation customers could be rendered until at least 2010. The NIPSCO Industrial Group argued that this requirement imposed unnecessary costs on transportation customers.

LaPorte County supported and joined the OUCC's *Motion* and requested that the Commission grant the OUCC's *Motion to Dismiss*.

The OUCC submitted a *Reply* to Petitioner's and the NIPSCO Industrial Group's opposition to its *Motion*. The OUCC asserted that the 1983 Generic Order and the Commission's May 14, 1986 Order in Cause No. 37091 show the Commission's preference for addressing the appropriate amount of UAFG in a general rate proceeding. The OUCC expressed concern that the actual level of UAFG has proven elusive, noting the various explanations provided in Petitioner's evidence. The OUCC responded to the NIPSCO Industrial Group by noting that the NIPSCO Industrial Group is not a party to the settlement agreement containing the rate case moratorium. Therefore, the OUCC stated that the NIPSCO Industrial Group may initiate a review of NIPSCO's basic rates and charges prior to May 1, 2010 if it continues to believe that NIPSCO is receiving a windfall based on the UAFG percentage being charged to transportation customers.

The Commission finds the OUCC's *Motion to Dismiss* was timely submitted. The Commission has now heard all the evidence presented by the parties pertaining to the UAFG issue. The record is complete and the Commission will make its decision based on that record.

g. Commission Discussion and Findings on UAFG. We must resolve three issues relating to UAFG in this case: (1) whether Petitioner should be allowed to recover the cost of UAFG in its GCA filings exceeding $3.0 million for the portion of UAFG that is equal to or below 0.85%; (2) whether the UAFG percentage to be used in GCA filings should be based on a four year average or the most recent period; and (3) whether NIPSCO's GCA 10 period gas costs should be adjusted to reflect NIPSCO's actual UAFG experience.

Traditionally, the Commission has reviewed the appropriate amount of UAFG as part of a rate case.[3] The Commission addressed the issue of recovery of UAFG costs as "[o]ne of the most

[3] *In the Matter of the South Eastern Indiana Nat. Gas Co. to Increase Its present Rates and Charges*, Cause No. 39186, 1991 Ind. PUC LEXIS 353, *7-8 (Ind. Util. Regulatory Comm'n Nov. 1, 1991);*In the Matter of the Petition of the City of Linton for Approval of a New Schedule of Gas Rates and Charges*, Cause No. 37663, 1985 Ind. PUC LEXIS 92, *11-12 (Ind. Util. Regulatory Comm'n Oct. 30, 1985); *In the Matter of the Petition of Community Nat. Gas Co., Inc. to Increase Its Rates and Charges*, Cause No. 37173, 1983 Ind. PUC LEXIS 208, *22 (Ind. Util. Regulatory Comm'n Sept. 28, 1983); *Petition of Ohio Valley Gas Corp. for Authority to Increase Its Rates and Charges*, Cause No. 36855, 1982 Ind. PUC LEXIS 52 (Ind. Util. Regulatory Comm'n Dec. 1,

controversial issues" in the Commission's generic GCA proceeding. *In the Matter of an Investigation into Existing Gas Cost Tracking Procedures Utilized by Gas Distributing Utilities,* Cause No. 37091, 1983 Ind. PUC LEXIS 308, *17, (Ind. Util. Regulatory Comm'n Aug. 3, 1983)("Generic GCA Proceeding").We noted that even in the context of a base rate case, the recovery of costs associated with UAFG had often been disputed, and even when found not be excessive, the Commission ordered that utilities "immediately correct situations which increase the level of [UAFG]." *Id.* at *18-19. We recognized then a principal that we have continued to employ over the years.

> While this Commission recognizes that a minimal amount of gas will not be accounted for with even the most circumspect utility practice, we completely reject the notion that all costs for unaccounted-for-gas, regardless of its magnitude or causes, are an acceptable cost of doing business for gas distributing utilities. An acceptable amount of unaccounted-for-gas will reasonably vary from utility to utility based upon the unique circumstances surrounding the utility's operation. Whether a specific amount of unaccounted-for-gas is reasonable and should therefore be recovered from a utility's ratepayers is an extremely fact sensitive determination which, we believe, is best retained in the broad based inquiry of a general rate proceeding. Ultimately we agree with the Public's position that the recovery of cost associated with unaccounted-for-gas through the periodic gas costs adjustment procedure would tend to diminish the incentive for utilities to reduce the level of unaccounted-for-gas.

Id. at *19-20.

We further discussed the methodology of GCAs and the role of UAFG in such proceedings in the *Generic GCA Proceeding*'s Order of May 14, 1986 ("1986 Generic Order"), 1986 Ind. PUC LEXIS 339.

> The Commission believes the legislature did not intend the gas cost adjustment procedure to be a full rate case assuring a dollar for dollar recovery of all changes in cost incurred by the utility during the adjustment period.

Id. at *6.

> . . .

> Currently, unaccounted for gas costs are recovered through base rates at the level allowed by the Commission in the utility's last general rate proceeding. Thus, if the actual level increases above the base level, the additional cost is unrecovered, while, if the actual level decreases, the utility realizes a "profit."

Id. at *7-8.

> . . .

1982); *Petition of Indiana Gas Co., Inc. for Authority to Adjust and Increase Its Existing Rates and Charges,* Cause No. 36816, 1982 Ind. PUC LEXIS 115, *16-18, 22-23 (Ind. Util. Regulatory Comm'n Oct. 27, 1982).

> Based on the Commission's two years of experience with the GCA mechanism subsequent to our original order [on August 3, 1983], we remain convinced that the causes of unaccounted for gas are both too fact sensitive and indicative of too wide a range of proper Commission and utility responsive action to be includable in the GCA mechanism....Indeed, even the Respondents advocating inclusion of unaccounted for gas in the mechanism acknowledge the wide array of causes which can be responsible for this phenomenon. Therefore the Commission finds that the appropriate level of unaccounted for gas is more properly determinable in a general rate proceeding, as opposed to a summary proceeding, and that changes in the unaccounted for gas should not be tracked in the quarterly (or semi-annually as found proper in some cases ...below) GCA mechanism.

Id. at *11-12 (citation omitted.)

1. Whether Petitioner should be allowed to recover UAFG costs exceeding the $3.0 million determined in its last rate case in its GCA filings for the portion of UAFG that is equal to or less than 0.85%. Mr. Martin testified that Petitioner is proposing to recover UAFG dollars that are in excess of the $3 million recovered in base rates, for UAFG at or below .85%. Martin, Supp. at p. 12. He stated that the UAFG would be based on a four-year historic average determined on a rolling basis.

The OUCC opposed Petitioner's request, arguing that the Commission indicated over twenty-five years ago its preference to review UAFG costs in the context of an Indiana gas utility's general base rate case. OUCC witness Mr. Mierzwa echoed this position in his direct testimony, opining that the recovery of UAFG is best reviewed in a general base rate case proceeding and that it is improper single issue ratemaking to isolate one rate case expense for consideration, i.e., UAFG costs, without considering changes in the other costs of providing service. Mierzwa, p.4.

In its Response to the OUCC's *Motion to Dismiss* ("Response"), Petitioner agreed that the establishment of a baseline *volume* of UAFG for a utility is an extremely fact-sensitive determination that is best retained in a base rate proceeding, but argued that the determination of the *cost* associated with that volume can routinely be determined in a summary GCA proceeding. Mr. Martin stated that Petitioner is not requesting a change in the *magnitude* of UAFG, but only the *cost* associated with the rate-case-established UAFG magnitude. Martin, Supp. at p.9.

Petitioner also indicated in its *Response* that the Commission has authority to approve cost tracking mechanisms pursuant to I.C. 8-1-2-42(a) and (g). Petitioner testified through Mr. Martin that UAFG is a gas cost, and is therefore eligible for recovery through a Commission–approved recovery mechanism. Martin, Supp. p.8; Rebuttal, p.3. Petitioner noted in both its Response and in testimony that three Indiana utilities are already permitted to recover through the GCA mechanism the actual cost of gas related to UAFG up to the percentage that was established in a rate case. Martin, Supp. p.11. Petitioner also argues in its proposed order that nothing in our prior orders precludes granting this relief. However, in its *Motion to Dismiss*, the OUCC stressed that two of those utilities are doing so pursuant to rate case settlements. The OUCC testified that the third utility, Citizens Gas, began recovering the actual cost of UAFG (up to an agreed UAFG percentage) pursuant to a settlement that took place within a year after new rates had been implemented.

We conclude that Petitioner should not be authorized to recover UAFG costs through the GCA mechanism in this Cause.

As noted by the OUCC, we have approved settlement agreements in recent natural gas rate cases which allow UAFG costs to be recovered through GCA mechanisms and not through base rates. *Petition of S. Indiana Gas & Elec. Co. d/b/a Vectren Energy Delivery of Indiana, Inc.,* Cause No. 43112, 2007 Ind. PUC LEXIS 232 (Ind. Util. Regulatory Comm'n Aug. 1, 2007)("Vectren South"); *Petition of Indiana Gas Co., Inc. d/b/a Vectren Energy Delivery of Indiana, Inc.,* Cause No. 43298, 2008 Ind. PUC LEXIS 104 (Ind. Util. Regulatory Comm'n Feb. 13, 2008)("Vectren North"). The OUCC worked with both Vectren South and Vectren North in their respective rate cases to structure settlement agreements that address the UAFG issue. The settlement agreements in those Causes provide for the recovery in the GCA of the actual cost of UAFG volumes, up to an agreed UAFG percentage. See, *Vectren North* at *31, *85-86; *Vectren South,* at *48-49, *88.

In *Vectren South,* we noted that the tracking of UAFG through the GCA removed the allowance for UAFG from base rates. *Vectren South,* at *42. This process also included an annual reconciliation of actual UAFG costs. *Id.* at *49. The OUCC noted that the traditional method of allowing recovery of UAFG in base rates "arguably provides the maximum incentive for utilities to minimize UAFG." *Id.* at *66. The OUCC was willing to agree to tracking UAFG costs through the GCA "if incentives to manage the UAFG ratio were retained", which was accomplished through the negotiated percentage UAFG ratio cap. *Id.* at *67. The Commission found that Vectren South "would continue to have a financial incentive to minimize UAFG costs...due to limitations on the recovery of related gas costs in GCA proceedings." *Id.* at *72. *Vectren North* contained similar provisions. *Vectren North* at *30, *53-54, *86-87.

In addition, Citizens Gas' recovery of UAFG costs through the GCA process is the indirect result of a rate case settlement agreement. *See, Petition of the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis,* Cause No. 37399 GCA 95, 2007 Ind. PUC LEXIS 252, *15-19 (Ind. Util. Regulatory Comm'n Aug. 29, 2007)("Citizens Gas"). Citizens Gas filed new base rates on October 23, 2006, but inadvertently did not include the amount of UAFG costs the Commission authorized by its Order in Cause No. 42767. We noted the continuing consequences of this error.

> [Citizens Gas] removed the total amount of gas costs (including UAFG costs) from the authorized level of revenue requirements in the determination of base rates, which resulted in a failure to recover any amount for UAFG costs. Citizens Gas also...excluded UAFG costs in its [subsequent] GCA filings on the premise that those costs [were being] recovered in its base rates....[Thus] Citizens Gas [was] not recovering its authorized UAFG costs from customers in base rates or in its GCA rates.

Id. at *16.

This oversight continued for several months, and Citizens Gas requested relief when it filed its petition on June 29, 2007 in Cause No. 37399 GCA 95. Citizens Gas and the OUCC met to resolve Citizens' unrecovered UAFG costs, and eventually agreed that the procedure adopted by the Commission in its Order in Cause No. 43112 for Vectren South would be the method that should be used for the recovery of Citizens Gas' UAFG costs. Specifically, Citizens Gas and the OUCC agreed the remedy to the under-recovery of UAFG costs was for Citizens Gas to be authorized to recover its actual UAFG costs through GCA rates up to the UAFG percentage of 1.124%, which was included in Cause No. 42767, Citizens Gas' last rate case prior to GCA 95. The Commission authorized Citizens Gas to recover UAFG costs in the GCA with the following finding:

> We reiterate our prior finding that Citizens Gas should be recovering the authorized level of UAFG costs *in its rates and charges for service*. However, due to an error in the calculation of the base rates filed on October 23, 2006, Citizens Gas has not been recovering UAFG costs in its base rates, nor is Citizens Gas recovering the UAFG costs in the GCA. Based upon the evidence of record, we find that Citizens Gas should be authorized to recover its UAFG costs in the GCA through the proposed procedure described above. Both the OUCC and Petitioner may address the UAFG cost recovery procedure in the next GCA proceeding.

Id. at *18 (emphasis added).

Thus, while we have allowed utilities to recover UAFG costs through the GCA mechanism, those allowances have been as a result of settlements that the Commission then layered with oversight requirements. Each case is clearly distinguishable from NIPSCO's request at bar and there is another factor present here absent in all the prior cases: in no circumstance have we allowed a utility to recover UAFG through *both* base rates and the GCA process. We have been careful to limit the recovery of UAFG through the GCA process by requiring strict oversight and annual true-up mechanisms subject to potential modification.[4]

The Commission has repeatedly stated its preference for reviewing UAFG costs in the context of an Indiana gas utility's general base rate case. That preference has not changed. Vectren North and Vectren South were only permitted to recover UAFG costs through the GCA after a "fact-sensitive" determination had been made in their immediate rate cases. Citizens Gas did not request recovery of UAFG costs through the GCA in its base rate case (Cause No. 42767). But the Commission allowed that relief under extenuating circumstances within one year of the Commission's Order in Cause No. 42767.

It has been over twenty years since the Commission issued NIPSCO's last natural gas rate case Order in Cause No. 38380 on October 26, 1988. As the OUCC noted in its *Motion to Dismiss*, NIPSCO's UAFG costs may have changed in the last two decades. Similarly, other operation and maintenance (O&M) and administrative expenses have changed, through increase, decrease, elimination, or creation of new items. The number of natural gas customers supplied and employees

[4] *Vectren South* at *49; *Vectren North* at *31; *Citizens Gas* at *18.

employed by NIPSCO has changed. Similarly, as noted by the OUCC, accounts receivable and NIPSCO's return on equity (ROE) might be significantly different today than what was determined in NIPSCO's last rate case.

In short, multiple factors go into the determination of rates, and to isolate UAFG expense for consideration provides an incomplete and potentially inaccurate view of NIPSCO's financial situation. NIPSCO has argued that natural gas price volatility, non-existent when the Commission issued its generic GCA Orders in 1983 and 1986, makes it currently very difficult for any gas utility to appropriately and fairly value the cost of UAFG in a base rate case. We note that the Vectren North, Vectren South and Citizens Gas rate case settlement agreements were approved in the last two years when natural gas prices have been volatile. Even assuming *arguendo* that NIPSCO's argument has merit, such an argument standing alone does not justify the rejection of a significant policy held by the Commission for twenty-five years. The Commission finds that Petitioner should not be authorized to recover UAFG costs through the GCA mechanism. This issue may be addressed in Petitioner's next rate case if it chooses.

NIPSCO Industrial Group has argued that Petitioner's reduction in system-wide UAFG carries the implication that Petitioner's transportation customers (which according to Mr. Martin, includes Choice marketers) are subsidizing GCA customers. Accordingly, NIPSCO Industrial Group is seeking adjustments to the retention rate charged to transportation customers, which at present is set by tariff at 0.85%. The evidence indicates that Petitioner does not have the capability to separately meter transportation customers versus GCA customers, and therefore it is not possible for Petitioner to determine whether lost gas experienced by transportation customers is higher or lower than the UAFG experienced by GCA customers. Mr. Martin indicated in his rebuttal testimony and during cross examination that Petitioner is not fundamentally opposed to filing tariffs to update the transportation customers' retainage percentage on a periodic basis. However, he stated that more study is needed to fully understand the appropriate retainage amount for transportation customers delivering gas into Petitioner's distribution system. Martin, Rebuttal, p. 9. The Commission finds that Petitioner should study the issue and inform this Commission, the NIPSCO Industrial Group, LaPorte County and the OUCC within twelve months of the date of the order in this Cause the status of the study and the position Petitioner will take on this issue.

2. ***Whether the UAFG percentage to be used in GCA filings should be based on a four-year average, or based on the most recent year's UAFG.*** Petitioner's witness Martin proposed that a rolling four-year average should be used to determine the UAFG percentage occurring on Petitioner's system. He stated that doing so would eliminate abnormalities like weather impact, load growth that affects seasonality, and unusual balancing impacts. Martin, Supp. p.12.

The OUCC disagreed with the use of a four-year average. Mr. Mierzwa testified against the use of any average, although he stated he was not opposed to the use of an average when determining the retainage to be assessed transportation customers. Tr. at B-71-72. Mr. Mierzwa testified that 0.73% for the most recent year would be a more appropriate UAFG percentage because it reflected only current UAFG.

The Commission finds that the appropriate UAFG percentage should be the current actual

UAFG for the GCA period. Therefore, the Commission also finds that the UAFG percentage for the GCA 10 period is 0.73%. With this finding, the Commission now must determine the third issue related to the UAFG issue.

3. ***Whether NIPSCO's GCA 10 period gas costs should be adjusted to reflect NIPSCO's actual UAFG experience.*** As noted in section 4.b. above, Mr. Mierzwa testified that NIPSCO did not accurately reflect UAFG costs in its GCA10 filings. He stated that NIPSCO witness Martin testified NIPSCO utilized a UAFG factor of 0.15% in prior annual GCA filings, including its GCA 10 filing, but a recent analysis has determined that NIPSCO's actual UAFG experience during the GCA 10 period was 0.73%. *See* NIPSCO Exhibit 3, Attachment B, Column Aug 2007 – July 2008, line 14.

Mr. Mierzwa testified about the implications of the difference between using a 0.15% and a 0.73% UAFG factor. He testified that NIPSCO collects $3.0 million of UAFG costs through *base distribution rates*. This amount was purportedly based on a system-wide UAFG rate of 0.85%. Consequently, in order to prevent a double collection from customers, UAFG costs are deducted from NIPSCO's gas costs for GCA purposes. During the GCA 10 period, the UAFG costs deducted from gas costs were based on a factor of 0.15%. NIPSCO witness Martin presents an analysis for the GCA 10 period (Aug 2007 – July 2008) indicating that NIPSCO's actual UAFG experience was 0.73%. NIPSCO Exhibit 3, Attachment B. Thus, at a minimum, the amount deducted from gas costs for UAFG during the GCA 10 period was understated as indicated in the chart below. Therefore, Mr. Mierzwa recommended that GCA 10 period gas costs be adjusted to reflect NIPSCO's actual UAFG experience. As shown below, Mr. Mierzwa recommended GCA 10 gas costs should be reduced by approximately $4.1 million.

Adjustment to Gas Costs to Reflect
Actual Unaccounted-For Experience

UAFG Actual Experience	0.73 %
UAFG Factor Reflected in Monthly GCA 10 Filings	0.15 %
Increase in Actual UAFG Gas (.73 / .15)	487 %
GCA 10 UAFG Costs Based on Actual Experience ($1,057,082 x 4.8667 [487%])	$5,144,500
Cost of UAFG Reflected in GCA 10 Filings (Sch. 11, line 9, p.4)	$1,057,082
Adjustment to Gas Costs to Reflect Actual UAFG Expense	$4,087,418

Difference Between UAFG Costs Collected In Base Rates And GCA 10 UAFG Costs	
UAFG Costs Collected in Base Rates (Martin Supp. Test. p. 4)	$3,000,000
Cost of UAFG Costs Reflected in GCA 10 Filings (Sch. 11, line 9, p. 4)	$1,057,082
Difference	$1,942,918
In this example NIPSCO profits $1,942,918 from UAFG.	

GCA 10 UAFG Costs Based on Actual Experience	$5,144,500
UAFG Costs Collected in Base Rates (Martin Supp. Test. p. 4)	$3,000,000
Difference	($2,144,500)
(In this example UAFG would cost NIPSCO $2,144,500)	

The Commission finds Mr. Mierzwa's analysis accurately reflects NIPSCO's true UAFG costs during the GCA 10 period. Therefore, the Commission finds that NIPSCO's GCA 10 total gas costs should be reduced by $4,087,418 to reflect actual UAFG expense. Petitioner will return the $4.1 million as a one-time refund to rate payers in the next quarterly filing.

5. **Petitioner's Capacity Reserves.**

a. Petitioner's Evidence. Mr. Karl Stanley, Executive Director, Energy Supply and Trading for Petitioner, described the various sources of natural gas to be purchased by Petitioner during the twelve months beginning November 1, 2008. Mr. Stanley explained that Petitioner's objective is to secure reliable firm gas supply at the lowest cost reasonably possible in order to meet current and anticipated customer requirements. He stated that Petitioner manages a balanced and fully diversified gas supply portfolio comprised of a variety of commodity, transportation and storage resources to achieve this objective. During the twelve-month period beginning November 1, 2008, Petitioner will purchase supply under arrangements on both a term and spot market basis. In order to achieve diversity of supply, Petitioner has entered into 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 will have an aggregate Maximum Daily Quantity ("MDQ") during the peak season of 510,251 Dekatherms ("Dth") and an off-peak MDQ of 341,649 Dth. Firm storage service contracts with Natural, Panhandle, ANR, Moss

Bluff Hub Partners, L.P. ("Moss"), Kinder Morgan Texas Pipeline, L.P. ("KMTP"), ENSTOR Operating Company ("Katy") and Egan Hub Partners, L.P. ("Egan") are anticipated to provide annual storage volumes of 32,758,651 Dth, with a maximum daily withdrawal capacity of 651,126 Dth to meet winter peaks. These contracted supplies are reinforced with Company-owned underground storage with a capacity of 6,750,000 Dth and LNG storage with a capacity of 4,000,000 Dth, both of which are located within Petitioner's service territory. Mr. Stanley stated that during a design peak day, 77% of the projected peak demand can be supplied by storage, 19% can be supplied with transported supply and 4% can be supplied with citygate delivered supply.

Mr. Stanley also described Petitioner's competitive bidding process. He stated that twice a year, Petitioner conducts a Request for Proposal ("RFP") process to secure bids for term and firm gas supplies. One RFP is prepared for the peak season and a second is prepared for the off-peak season. According to Mr. Stanley, the RFP process is used to contract for firm gas supply at specific points, under known pricing methods, for a defined period of time. He said the RFP process also includes a determination of the volume of gas that can be received by Petitioner each day, month, and/or season with minimum and maximum supply constraints. This evaluation takes into account projected customer demand requirements in addition to storage and transportation rights.

Mr. Stanley testified that Petitioner solicits bids from current and potential trading partners via an RFP form requesting bids on a variety of deal structures and pricing at specific locations. The bids are reviewed, taking into account current market conditions, value to customers, application to portfolio, and supplier financial condition and historical performance. He said that historically through the RFP process, Petitioner has awarded a variety of deal structures to multiple suppliers at a variety of locations to create the most competitive, low/cost, and diversified portfolio reasonably possible. Mr. Stanley noted that Petitioner purchased gas supplies from 34 different suppliers during the winter period of November, 2007 through March, 2008.

Mr. Stanley also described transportation agreements, which permit Petitioner to transport additional volumes of natural gas to its distribution system when needed. Petitioner has short-haul firm transportation agreements with both Panhandle (MDQ of 20,000 Dth) and Trunkline (MDQ of 35,000 Dth), the purpose of which is to move gas between Petitioner's Zones "A" and "B" service areas. Additionally, Petitioner has short-haul firm transportation contracts with Vector (MDQ of 43,000 Dth), Border (MDQ of 165,000 Dth), and Panhandle (MDQ of 15,165 Dth).

Mr. Stanley also reviewed the major changes in Petitioner's contractual agreements since the filing of his testimony in Cause No. 41338 – GCA9. Those changes are (1) negotiations were completed to replace transportation and storage services that expired on March 31, 2008; (2) Petitioner has negotiated transportation and storage services with ANR, Katy, Moss Bluff and Washington 10 Storage Corporation; and (3) negotiations are underway to replace storage and transportation services with Natural, Panhandle and Trunkline that will expire on March 31, 2009.

b. OUCC Evidence. Mr. Mierzwa questioned Petitioner's reserve capacity and peak day demand design. He explained that Petitioner's interstate pipeline capacity planning procedures involve reserving sufficient interstate pipeline and storage capacity to meet the design peak day demands of its GCA sales and Choice transportation customers. Mr. Mierzwa discussed six concerns with Petitioner's methodology which had the affect of overstating peak day demand design.

First, he noted that Petitioner's design peak day demand forecast should be reduced by 38,000 Dth to match the revised forecast provided by Petitioner in response to an OUCC discovery request.

Second, Mr. Mierzwa took issue with Petitioner's use of a 95% reliability allowance to gas supplies delivered from market and production area storage facilities and an 80% reliability allowance to gas flowing under its interstate pipeline firm transportation agreements. He explained that such an approach assumes that 5% of the total storage capacity and 20% of interstate pipeline firm transportation will not be available on a design peak day. Mr. Mierzwa did not believe Petitioner's use of reliability allowances was reasonable.

Third, Mr. Mierzwa explained that it is no longer reasonable to include reliability allowances in Petitioner's capacity planning criteria. Mr. Mierzwa explained that reliability allowances were adopted in the mid-1990s because of the uncertainty of operating in a new environment after the FERC had required interstate pipelines to abandon the merchant function in Order No. 636. Mr. Mierzwa did not believe this uncertainty continues to exist today and opined that the use of reliability allowances is inconsistent with current standard industry practice. He cited examples of utilities from Ohio and Indiana that no longer utilize reliability allowances.

Fourth, Mr. Mierzwa believed Petitioner's peak day design, which has a 3% probability of occurrence, is inconsistent with industry practice. He opined that industry practice is to design a peak day with 5-10% probability of occurrence. The effect of this design is to provide an additional reserve margin.

Fifth, Mr. Mierzwa noted that Petitioner reserves sufficient interstate pipeline and storage capacity to meet 100% of design peak day demands of customers participating in its customer Choice program. Mr. Mierzwa believes it is highly unlikely that all suppliers serving Choice customers would fail to deliver any gas to Petitioner on a design peak day, rendering unnecessary the reservation of capacity to serve 100% of the design peak day demands for Choice customers. He believed some portion of the design peak day for Choice customers would be greater.

Finally, Mr. Mierzwa did not believe that Petitioner's interruption experience with interstate pipelines justifies Petitioner's retention of reserve allowances. He based this conclusion on a review of information Petitioner provided regarding recent experiences with such interruptions. Mr. Mierzwa acknowledged that Petitioner has indicated it is planning to reduce the amount of interstate pipeline capacity it reserves by 62,100 Dth, but believed that a further reduction of approximately 100,000 Dth would be appropriate.

Mr. Mierzwa testified that Petitioner should shed capacity in a manner which reduces total gas costs over the long term by the greatest amount. He recommended Petitioner maximize the utilization of capacity in the Mid-Continent region and noted Petitioner often does not maximize the use of such capacity. He acknowledged Petitioner has subsequently been successful in obtaining additional value from its Mid-Continent capacity during the winter of 2008-2009.

c. **Petitioner's Rebuttal Evidence**. Mr. Stanley disagreed with Mr. Mierzwa's recommendation that Petitioner reduce its interstate pipeline capacity by an additional 100,000 Dth per day. He responded specifically to Mr. Mierzwa's criticisms, beginning with the recommendation that Petitioner reserve less than 100 % of the needs of all sales and Choice customers on a peak day. Mr. Stanley noted that if market prices rise high enough whereby choice marketers would not have sufficient credit to cover all their supply needs, this could precipitate a failure of all suppliers at one time and the duty to supply would fall back on Petitioner.

Mr. Stanley also disagreed with Mr. Mierzwa's recommendation that Petitioner eliminate its reliability allowances of 95% for storage capacity and 80% for interstate pipeline capacity. Mr. Stanley disputed Mr. Mierzwa's contention that maintaining reliability allowances is no longer the industry practice, noting that one of the Ohio orders cited by Mr. Mierzwa expressly recognized that many utilities have reserve margins and recognized that reserve margins may be reasonable. He stated that Petitioner's unique position should be accounted for and that reducing reserve margins would cause Petitioner to become increasingly reliant on citygate purchases, potentially leading to very high supply costs in times of extreme distress.

Mr. Stanley also cited several recent examples of pipeline interruptions and storage failures where Petitioner's reserve margins protected it from becoming overly reliant on citygate purchases. He explained that during the entire winter of 2007-2008, NGPL experienced an interruption that restricted deliveries on its pipeline to between 75% and 95% of total firm capacity, thus limiting winter deliverability. During January and February of 2007, water in NGPL's lines restricted deliveries into Petitioner's system by 20,000 Dth per day. Mr. Stanley described Panhandle's service problems between November 2007 and January 2008 that restricted deliveries to between 85% and 90% of total firm capacity. Mr. Stanley also disagreed with Mr. Mierzwa's explanation of the available coverage during a problem with the Moss Bluff storage facility as failing to consider the significant upward price pressure that could result if the failure had occurred during a period of extreme market distress. Mr. Stanley concluded that the reserve margins provide a needed cushion so that Petitioner does not concentrate its price risk at one delivery location, thereby driving up the cost of gas supply.

Mr. Stanley also described the problems with relinquishing storage and transportation capacity. He noted that it may be difficult to re-contract for capacity once it is relinquished because Petitioner has recently seen transportation and storage agreements that have locked up capacity for periods ranging between 4 to 15 years. Were Petitioner to relinquish its capacity as recommended by Mr. Mierzwa, Mr. Stanley expressed concerns about the ability to get back the capacity if it proved necessary to reinstate Petitioner's reserves. Moreover, Mr. Stanley explained that it is not known whether the transportation and storage contracts that are relinquished will save more money than the increased gas supply costs that could result if additional gas supply must be purchased at the Petitioner's citygate.

d. **Commission Discussion and Findings on Reserve Requirements**. OUCC witness Mr. Mierzwa stated in his direct testimony that Petitioner's use of reliability allowances is no longer reasonable and should be eliminated from Petitioner's planning criteria. He testified that Petitioner applies a 95% reliability allowance to gas supplies that are delivered from interstate pipeline and production area storage facilities, which assumes that 51,280 Dth will not be available on a design peak day. With regard to interstate pipelines firm transportation, Petitioner applies an 80% reliability allowance, which assumes that 72,020 Dth will not be delivered on a design peak day. Mr. Mierzwa also noted the reduction in peak day demand that was confirmed by the Petitioner's response to a data request. This change would reduce the design peak day demand by 38,000 Dth. By eliminating the reserve allowances and incorporating the reduction in peak day demand into its capacity planning criteria, Mr. Mierzwa recommended that Petitioner should reduce its interstate pipeline and storage capacity entitlements by 161,300 Dth.

Mr. Mierzwa asserted that reliability allowances were utilized by some gas utilities in the mid-1990s when the FERC required interstate pipelines to abandon the merchant function in Order No. 636, but the use of reliability allowances is inconsistent with current industry practice. Mr. Mierzwa further noted the interstate pipeline capacity reserved by Petitioner is sufficient to meet 100% of the needs of customers who participate in the Choice program, which on a peak day is estimated to be 208,000 Dth. Mr. Mierzwa suggested that it is highly unlikely that all Choice suppliers would fail at the same time, and therefore some of that 208,000 Dth of capacity reserve related to Choice customers could serve as a reserve allowance. This would further support the elimination of the current reserve allowance of 161,000 Dth/day.

Petitioner's witness Mr. Stanley defended the current reserve allowances maintained by Petitioner. He pointed out that Petitioner has supplier-of-last-resort responsibilities to Choice customers and disagreed with Mr. Mierzwa's assessment that the failure of all Choice suppliers is "highly unlikely." Mr. Stanley suggested that credit problems could precipitate a failure of all suppliers at one time, which would then require Petitioner to meet the supply requirements of those Choice customers. Mr. Stanley further defended Petitioner's reserve allowance by providing historical examples of interruptions. While supplies were available at the citygate to handle many of these interruptions, Mr. Stanley cautioned that depending on the number and duration of pipeline and storage outages, there could be severe upward price pressures if Petitioner tries to secure an ever larger supply at one price location to meet the needs of its system. He explained that reserve margins provide a cushion so that Petitioner does not concentrate its price risk at one delivery location thereby risking driving up the costs of gas supply. Next, Mr. Stanley pointed out that it may be difficult to re-contract for capacity once it is relinquished. As an example, he stated that some transportation and storage agreements have been locked up for anywhere from 4 to 15 years. Finally, Mr. Stanley stated that transportation and storage values can change over time.

While testifying, Mr. Stanley acknowledged there is a trade-off: if Petitioner did not maintain a reserve margin, it would be exposed to higher gas supply costs during periods of interruptions, but if it maintained a reserve, it would incur additional interstate pipeline demand charges. Tr. at C-20. The Commission understands the changing nature of the marketplace since unbundling occurred in the mid 1990's, and we also recognize the risks that could be presented by eliminating all reserve allowances when calculating Petitioner's peak day design portfolio. The potential for pipeline interruptions and storage failures still exists and must be considered to some degree when determining the appropriate balance between citygate purchases and portfolio pricing diversity. As noted in the hearing testimony, the OUCC and Petitioner agree there is a trade-off between the capacity costs associated with maintaining reserve allowances, versus the potential for significantly higher citygate prices during a peak day event. From the evidence presented, it appears that Petitioner's reserve allowance is justifiable.

6. **Storage Injection Pricing.**

a. OUCC Evidence. Mr. Mierzwa testified the Commission's Order in Cause No. 41338-GCA 4 required Petitioner to price its storage injections for GCA purchases at the weighted average storage year-to-date injection price based on year-to-date prices, volumes purchased and injection activity. However, he stated that Petitioner did not adhere to these storage pricing procedures for the months of August and October, 2007. According to Mr. Mierzwa, in those two months, Petitioner priced storage injections using only that current month's weighted cost of gas rather than the Commission-approved approach of using a weighted average year-to-date price. He urged the Commission to require Petitioner to use the method mandated in the GCA 4 Order.

b. Petitioner's Rebuttal Evidence. Ms. Cherven acknowledged that Petitioner used a different methodology for the months of August and October 2007, but noted that this difference was explained in a footnote on Petitioner's schedules and that no questions were raised about it. She testified that the different methodology was utilized to minimize significant GCA fluctuations from month to month. Based on the concerns expressed by Mr. Mierzwa, Ms. Cherven stated Petitioner will use the storage price as calculated on Schedule 5a.

c. Commission Discussion and Findings on Storage Pricing. The Commission finds that Petitioner must adhere to the storage pricing methodology approved and ordered in the GCA 4 order, and must calculate its storage price in accordance with Schedule 5a. The Commission fully expects its order regarding storage pricing to be consistently followed in the future. However, the Commission informs NIPSCO that footnotes on Petitioner's GCA schedules are inadequate to provide notice to the Commission, OUCC, and intervening parties, of substantive changes in pricing methodology. Therefore, in the future, if NIPSCO proposes to change any pricing methodology associated with its GCA filings, any such proposed changes should be clearly indicated, together with testimony supporting such a change.

7. **Undisputed Issues**.

a. Petitioner's Volatility Mitigation Issues. Mr. Stanley testified that Petitioner has continued its forward price volatility mitigation program for the 2008-2009 winter season. Mr. Stanley stated that Petitioner has established a plan that targets hedging the price on 20% of projected flowing gas supply purchase requirements for the winter months of November through March. Mr. Stanley said Petitioner has elected to achieve the hedge objective through the use of a dollar cost averaging method with the pre-planned purchase of NYMEX Future contracts at pre-planned execution times spread evenly across the preceding twelve month period. Mr. Stanley noted that the full effect of volatility mitigation hedging activity will be directly passed on to customers.

Mr. Stanley stated that Petitioner typically physically hedges approximately 40% to 50% of its firm sales customers' expected normal winter requirements through fixed price storage inventories. By establishing a 14% to 20% financial hedge on the remaining 60% of its winter supply requirements, Mr. Stanley said that Petitioner effectively hedges 50% to 65% of its firm sales customers' expected total normal winter requirements, depending on anticipated customer usage. Mr. Stanley believed that this level of hedging strikes an appropriate balance for customers in that it provides an appropriate amount of protection in the event of a price run-up, while allowing customers to receive some benefit in the event of declining prices. He also said that this level of hedging strikes a balance with various winter scenarios so that Petitioner is not over-hedged during a warmer than normal winter and under-hedged during a colder than normal winter. Mr. Stanley predicted that under normal weather conditions, approximately 51% of Petitioner's firm sales customers' requirements will be physically hedged through fixed price storage inventory and 11% will be hedged financially through NYMEX futures. That is, approximately 62% of anticipated firm sales requirements will be hedged for the 2008-2009 winter period. Mr. Stanley testified that, in his opinion, the Company's price volatility mitigation program is consistent with Paragraph 4 of the Stipulation and Settlement Agreement as approved by the Commission's August 18, 2004 Order in Cause No. 41338-GCA5.

On April 16, 2009 the Commission issued a Docket Entry asking if Petitioner has the ability to alter its gas procurement strategy to take advantage of the current low gas prices, and if so, what Petitioner planned to do to deviate from the current strategy. At the April 20, 2009 hearing, Mr. Stanley testified in response to the Docket Entry that Petitioner presently satisfies its customers' needs during the winter season using a pricing portfolio in which 50% is fixed through storage, roughly 12% is fixed through NYMEX futures contracts, and the remaining 37% is relegated to spot market purchases. Tr. at A-7-8. Mr. Stanley stated Petitioner has the ability to change its volatility mitigation plan and change the schedule by which Petitioner purchases those NYMEX future contracts. Mr. Stanley testified that Petitioner fills storage on a ratable basis, filling roughly one-seventh of its storage each month during the seven summer months. Thus, Petitioner is currently taking advantage of the perceived low prices as Petitioner fills storage this month. Tr. at A-37. Finally, Mr. Stanley noted that Petitioner faces operational constraints in order to get gas in the ground. Tr. at A-38.

The Commission has indicated 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 Petitioner has demonstrated it has and continues to follow a policy of securing natural gas supply designed to mitigate price volatility. However, testimony during this Cause indicated that part of Petitioner's gas purchasing strategy is to buy gas on a fixed date every month, thereby 'removing the price signal' from the purchase calculation. This approach works to counter volatility only to the extent that the market happens to be congruent with Petitioner's scheduled purchases. Therefore the Commission reminds Petitioner that Petitioner's Plan should include the flexibility to take advantage of current market conditions or opportunities to not only mitigate price volatility, but to effectively reduce the overall weighted cost of natural gas so as to provide the lowest gas cost reasonably possible in order to meet anticipated customer requirements. Given that Petitioner's current strategy does mitigate price volatility, the Commission finds the requirement of this statutory provision has been fulfilled.

b. Petitioner's Compliance With Audit Timeline. Ms. Cherven described the measures Petitioner has undertaken to comply with the provisions of the Stipulation and Settlement Agreement, ("Agreement") filed June 11, 2004 in Cause No. 41338-GCA5, as approved by the Commission's August 18, 2004 Order in that cause. Specifically, she noted that Paragraph 2C of the Agreement includes a detailed audit timeline, and Petitioner developed a similar timeline for GCA9 and has met each milestone of that timeline. No party disputed Ms. Cherven's testimony. Consequently, we find Petitioner has complied with the requirements of the Agreement.

c. Gas Cost Incentive Mechanism ("GCIM"). After describing the GCIM and the benchmark methodology, Mr. Mierzwa made the following findings and recommendations: (1) he found that Petitioner had adequately documented its actual cost claims, its GCIM and Interstate Pipeline Transportation Demand Cost Reduction Incentive Program ("DCRP") and such costs and results appear reasonable, and (2) he urged continuation of the procedures for the purpose of evaluating parks, loans and virtual storage ("PLVS") transactions agreed to in GCA9.

d. Computerized Optimization Planning. Mr. Mierzwa observed that Petitioner did not use a computerized optimization planning model to minimize its gas supply portfolio costs but noted that Petitioner is in the process of obtaining a computerized gas supply optimization planning model. Mr. Stanley noted that the gas supply optimization model will be up and running by the end of the third quarter. He explained that the role of the model will be to model what purchases should be made at each of the various supply locations assuming certain market conditions at the time. He stated that Petitioner intends to use this model as a resource.

8. <u>**Reconciliation**</u>. Ind. Code § 8-1-2-42(g)(3)(D) requires the Commission to find Petitioner reconciled its estimation for a previous recovery period with the actual purchased gas costs for that period. Witness Cherven testified Petitioner had net under-collected revenues for the period August 1, 2007 through July 31, 2008 of $87,451,182. Witness Cherven testified that Petitioner's net under-collection was due primarily to the actual commodity cost of gas being higher than estimates.

9. <u>**Resulting Gas Cost Adjustment Factors**</u>. Combining the total pipeline demand cost of gas to be recovered of $42,727,115 with the contracted storage and transmission costs of $37,577,162 and $108,778 results in total estimated annual demand costs of $80,413,055 for the twelve-month recovery period beginning with the November, 2008 billing cycle. After dividing by estimated annual sales, the requested annualized demand costs per therm are calculated for the November 1, 2008 - October 2009 period as follows:

Class 1 Residential	$.0933/therm
Class 2 General Service and Class 4 CNG	$.0734/therm
Class 3	$.0000/therm

With regard to the additional costs associated with Storage and Transmission, Petitioner offered evidence supporting the following charges:

FDTS	a charge of	$0.01640195/Therm

With regard to the Tiered Surcharge to Choice customers, Petitioner offered evidence supporting the following surcharges:

Residential	$0.0193/therm
Commercial	$0.0239/therm

All prior variances for these charges are included in Petitioner's monthly commodity filings.

10. **Interim Rates**. The Commission is unable to determine whether Petitioner will earn an excess return while this GCA is in effect. Accordingly, the Commission finds that the approved rates herein should be interim rates subject to refund, pending reconciliation of the gas costs in a subsequent GCA, and in the event an excess return is earned.

11. **Removal of Refund Obligation**. Our GCA 9 order imposed a refund obligation on Petitioner's GCA revenues for the period commencing August 1, 2007 through July 31, 2008, pending a reconciliation of Petitioner's gas costs and a determination as to whether an excess return has been earned. See *Northern Indiana Public Service Company*, Cause No. 41338-GCA 9 (Ind. Util. Regulatory Comm'n Feb. 27, 2008). Ms. Cherven stated that Petitioner is requesting the refund obligation be eliminated for the months of August through December, 2007 and January through July, 2008. She noted that a similar procedure had historically been established in the quarterly GCA filings. The testimony of Ms. Cherven reconciles Petitioner's estimated gas costs to its actual gas costs. Also, as a result of its quarterly NGA filings, the Commission finds that Petitioner has not earned an excess return during the twelve month period commencing August 1, 2007. Accordingly the Commission shall grant Petitioner's request that the refund obligation for this period be removed.

12. **Confidential Information.** On December 6, 2008, the Presiding Officers made preliminary findings that certain designated information marked "confidential" as requested in Petitioner's *Motions for Protection of Confidential and Proprietary Information* should be treated as confidential in accordance with I.C. § 5-14-3-4 and that confidential procedures should be followed with respect to this confidential information. Upon review of the confidential information submitted pursuant to the Presiding Officers' preliminary determinations, the Commission confirms its prior preliminary findings and concludes that the information for which Petitioner sought and the Commission preliminarily granted confidential treatment contains confidential, proprietary, competitively sensitive trade secret information that has economic value to Petitioner from neither being known to, nor ascertainable by, its competitors and other persons who could obtain economic value from the knowledge and the use of such information;. that the public disclosure of such information would have a substantial detrimental effect on Petitioner; and that the information is subject to efforts of Petitioner that are reasonable under the circumstances to maintain its secrecy. Accordingly, the confidential information in Petitioner's Exhibit 1D is exempt from the public access requirements of I.C. §§ 5-14-3-3 and 8-1-2-29 and shall continue to be held as confidential by the Commission.

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

1. In accordance with our finding in paragraph 4.g., NIPSCO's total gas costs shall be reduced by $4,087,418 to reflect actual UAFG expense. NIPSCO's GCA is hereby approved on an interim basis, subject to refund, until the gas costs are reconciled in a subsequent GCA, and in the event that an excess rate of return is earned.

2. In accordance with our finding in paragraph 6.c., NIPSCO shall adhere to the storage pricing methodology approved and ordered in the GCA 4 order, and must calculate its storage price in accordance with Schedule 5a.

3. Petitioner shall file with the Natural Gas Division of this Commission the tariff changes approved herein.

4. The refund obligation imposed by the February 27, 2008 Order in Cause No. 41338 GCA 9 for the twelve month period commencing August 1, 2007 is hereby removed.

5. Northern Indiana Public Service Company's request for confidential trade secret treatment is hereby granted, and such Confidential Information shall be excepted from public disclosure.

6. This Order shall be effective on and after the date of its approval.

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

APPROVED: OCT 21 2009

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

Brenda A. Howe

Brenda Howe
Secretary to the Commission