Indiana Utility Regulatory Commission

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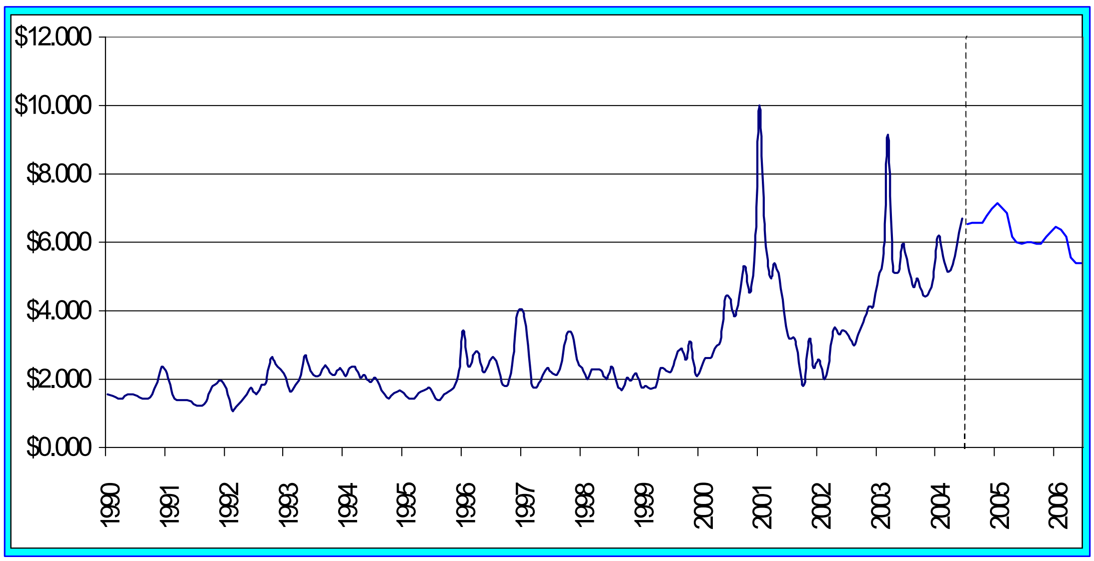
NYMEX Prices



Source: Vectren/Data Transmission
as of 6/04

2004

GAS REPORT

TO THE

REGULATORY FLEXIBILITY

COMMITTEE OF THE

INDIANA GENERAL ASSEMBLY

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EXECUTIVE SUMMARY

During the 2003–2004 heating season, natural gas prices surged as high as $7.00 per Mcf, but did not reach the peaks of high prices and volatility that were seen in the 2000–2001 or 2002–2003 winters.[1] The non-heating period of April through October is a time when demand has historically been lower and relatively inexpensive gas has been purchased and injected into storage for use in the coming winter. This summer did not follow that historical price norm as gas futures prices have hovered at a level about ten percent higher than a year ago and about sixty-percent higher than two summers ago.

As of September 1, 2004, NYMEX Natural Gas Futures Contracts for October 2004 through March 2005 delivery are in the $4.96 to $6.63 per Mcf range. [See NYMEX chart on pg. 10]. These futures prices have trended down significantly in recent weeks, even as oil prices have surged to record highs, yet they continue to be subject to unpredictable weather, economic factors, and government policies. A similar trend occurred during the 2003 summer when prices began the summer at high levels, trended downward toward late summer, then edged back up as we entered fall. What we can say for sure is that elevated natural gas prices are due, in part, to basic economic factors of supply and demand.

In purely economic terms, gas supply is tight. New sources and new technologies will alleviate some of the price pressure; but it will take time and will come at a high dollar cost. Demand, while down in some sectors, is not following the old path of peaking only during the winter season. Producers and local distribution companies (LDCs) continue to face the recent trend of a significant summer demand peak. The increased use of natural gas as the primary fuel source for electric peaking plants, typically designed to run during the summer months, is a major contributor to these summer demand peaks.

Indiana's LDCs have indicated their storage fields will be full for the upcoming winter, assuring gas supply and greater price stability for Indiana consumers. Gas utilities will also be stepping up their efforts to manage gas purchases aggressively to control costs through the use of portfolio management tools that emphasize dollar-cost-averaging, hedging, diversified purchasing practices and greater attention to non-traditional resources. The Commission will continue to encourage these kinds of efforts to ensure customers have gas available at the lowest price reasonably possible.

In addition to issues surrounding the volatile gas market, several major issues have been in the spotlight during the past year. They include a Universal Service Program proposal, a

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[1] Midwinter 2000-2001 NYMEX gas futures prices spiked to the $10 range. The 2002-2003 winter saw gas futures in the $5 to $6 range until late February 2003 when market forces led to another spike into the $10 range.

customer rights and responsibilities rulemaking, and a gas cost disallowance in Northern Indiana Public Service Company's gas cost adjustment (GCA) 4. These and other issues are highlighted in the following Report.

The pilot Universal Service Program, proposed by Citizens Gas and Coke Utility, Indiana Gas, and Southern Indiana Gas and Electric will assist eligible low-income customers by providing them with significant reductions in their natural gas bills. The two-year pilot program was filed under the Alternative Regulation statute and was approved by the Commission on August 18, 2004, thus allowing adequate time prior to the 2004-2005 winter heating season for eligible customers to take advantage of the program.

As a comprehensive way of addressing customer rights and responsibilities across all regulated industries, the Commission has published a Notice of Intent to Adopt and issued a Notice of Proposed Rulemaking. After public hearing and receipt of feedback, the Commission plans to issue a Final Rulemaking in the near future. The Rulemaking will address customer related issues such as creditworthiness, deposits, disconnections and reconnections, customer complaints, and estimated bills.

Following the volatile 2003 late winter price spike and protracted litigation in NIPSCO's gas cost adjustment proceeding (Cause No. 41338 GCA 4), the Commission ordered NIPSCO to refund $3.8 million to GCA customers during the 2003-2004 winter. The refund, along with other ordered changes in the GCA process, were deemed necessary due to NIPSCO's purchasing and storage practices during the period under review. The GCA 4 Orders led to many improvements in NIPSCO's GCA process, which culminated in the recent issuance of NIPSCO's GCA 5 Order. In a settlement reached with the OUCC, NIPSCO agreed to return an additional $3.8 million to GCA customers and to implement communication improvements.

Natural Gas Industry Overview

Industry Structure

Local gas distribution companies are generally either investor-owned or not-for-profit. Despite their different forms of ownership and corporate structures, investor-owned and not-for-profit utilities share the goal of providing reliable gas service at reasonable cost. These utilities serve as resellers and transporters of gas to their retail customers.

Typically, gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities, i.e. they are not vertically integrated.[2] LDCs buy their gas and transportation rights through contracts. Gas prices are set in the open market while the Federal Energy Regulatory Commission (FERC) regulates the transportation rates for interstate pipelines**.**

Investor-Owned Utilities

Investor-owned utilities (IOUs) are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large IOUs providing gas service, Indiana Gas Company, Inc. (IGC), Northern Indiana Public Service Company (NIPSCO) and Southern Indiana Gas and Electric Company, Inc. (SIGECO), and 16 smaller IOUs.[3] The three largest IOUs are owned by holding companies with NiSource as the parent of NIPSCO and Vectren owning Indiana Gas and SIGECO. Two of these companies, NIPSCO and SIGECO, are combination utilities that provide electric service as well as gas service.

Not-For-Profit Utilities

Not-for-profits are incorporated organizations in which no stockholder or trustee shares in profits or losses. In addition, they are exempt from corporate income taxes. On May 5, 2002, the Commission issued a Certificate of Territorial Authority (CTA) in its Order in Cause No. 42115 to Valley Rural Utility Company. Valley Rural is organized as a not-for-profit and is now providing service to a single residential development.

Municipals are organized as not-for-profit local government entities. They pay no federal taxes or dividends, although revenue can be turned over to the general city fund in lieu of taxes if the city elects to do so, and they raise capital through the issuance of tax-free bonds. There are 19 municipally owned gas utilities in Indiana, but only two are regulated by the Indiana Utility Regulatory Commission (IURC or Commission). The state's largest municipal gas utility, Citizens Gas and Coke Utility (Citizens)[4],

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[2] Vertical integration is a firm's involvement in all stages of the production of goods, from the procurement of raw materials to the sale of finished goods.

[3] On February 5, 2003, the Commission approved a Settlement Agreement in Cause Nos. 42246 and 42247 that authorized the operational merger of Midwest Natural Gas Corporation and Peoples Gas and Power Company, Inc. along with changes in rates and charges.

[4] Citizens was chartered in 1887 as a Public Charitable Trust. A charitable trust is organized to serve private or public charitable purposes. A charitable trust is usually a non-profit organization which has to account for its activities (especially financial) to the government. There is normally an obligation to register a non-profitable charitable organization as the public is entitled to some oversight of organizations that wish to act for the public good. Citizens is generally treated as if it were a municipal utility.

which serves Marion County, and Aurora Municipal Utility are the only two regulated by the Commission. Many municipal utilities have "opted out" of the Commission's jurisdiction.[5]

Indiana Sales and Transportation of Gas

Gas utilities serve as both merchants providing bundled sales and transportation service to many of their customers and transporters moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers. Interstate pipeline companies transport gas to the points of delivery (also known as City Gates) where it enters the LDC's system for distribution to its customers.

Table 1 presents sales information for Indiana's four largest LDCs: Citizens Gas, Indiana Gas, NIPSCO, and SIGECO. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the provision of gas and its transportation. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix A.[6]

TABLE 1

Total Sales (Dth[7]) by Class for the Four Largest Gas Utilities in Indiana – 2003

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	24,725,447	14,531,687	2,222,937	4,328,071	45,808,142
Indiana Gas	48,144,000	20,197,000	576,000	-	68,917,000
NIPSCO	60,236,514	24,698,311	14,118,973	1,243,411	100,297,209
SIGECO	8,454,811	4,074,229	522,944	7,221	13,059,205
TOTAL	**141,560,772**	**63,501,227**	**17,440,854**	**5,578,703**	**228,081,556**

Source: IURC Company Annual Reports on file with the IURC

The Natural Gas Market

2003–2004 Winter Market Conditions

Natural gas supplies meet one-fourth of the United States' energy needs. As a result of the deregulation and commodization of natural gas, market conditions now impact residential, commercial and industrial consumers almost immediately. This past winter again proved this economic reality.

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[5] A municipally owned utility may be removed from the jurisdiction of the commission for the approval of rates and charges and of the issuance of stocks, bonds, notes, or other evidence of indebtedness, if the municipal legislative body adopts an ordinance removing the utility from commission jurisdiction. (IC 8-1.5-3-9.1).

[6] Retail sales are typically categorized by class of customer, i.e., the residential, commercial and industrial customers. The designation "other" refers to sales to public authorities, i.e., governmental entities.

[7] For purposes of this Report, 1 Dekatherm (Dth) = 1 thousand cubic feet (Mcf) = 1 MMBtu.

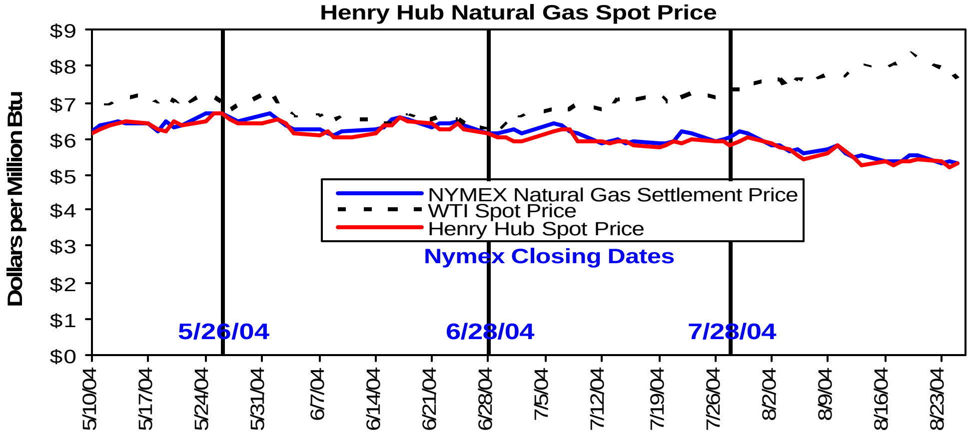
Market indicators for the 2003–2004 heating season suggested that gas bills were going to be higher than for the prior heating season because of increasing demand and prices. Anticipating this scenario, all of the major gas utilities conducted public relation campaigns to warn their customers that gas bills would likely increase, perhaps significantly, from the prior year. Customers were told that the return of normal weather and increases in the average price of gas would alone raise gas bills over those of winter 2002–2003.

Fortunately for consumers, the 2003-2004 winter weather was less severe than originally expected. Winter temperatures for 2003-2004 were average when compared to the previous 10 years. However, several early cold snaps in the East and Northeast helped to drive and sustain elevated prices. Natural gas in storage across the country was near a five year high at the start of the heating season and stayed within the five year historical range for the remainder of the winter.[8]

During last summer and into the fall, an unusually high number of traders acquired short positions for NYMEX natural gas contracts through the winter months. As the early onset of cold temperatures drove up prices and the margin requirements on NYMEX futures contracts increased, many traders were forced to cover their short positions. This also helped to bid up and sustain gas prices.

Another factor that increased the price for natural gas was the threat of reduction in oil supply because of the continued U.S. involvement in Iraq. All of these variables converged to put upward pressure on gas prices, causing them to increase from $4.50 per Mcf [9] in the fall of 2003 to over $7.00 per Mcf by January 2004.

NYMEX Natural Gas Futures Near-Month Contract Settlement Price, West Texas Intermediate Crude Oil Spot Price, and Henry Hub Natural Gas Spot Price



Note:The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.
Source: NGI's *Daily Gas Price Index* (http://Intelligencepress.com)

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[8] EIA Natural Gas Weekly Storage Update as of July 2, 2004
[9] For purposes of this Report, 1 Dekatherm (Dth) = 1 thousand cubic feet (Mcf) = 1 MMBtu.

Although sharp increases in residential heating bills were evident in the 2003–2004 winter season they were still below the level seen during the 2000–2001 winter. During that winter, very low storage levels at the onset of the season and a cumulative slump in new supply capacity caused an even sharper spike in natural gas prices.

Market Projections for Gas Prices and Demand

A competitive market determines gas prices. Unfortunately for gas consumers, gas prices can be expected to continue to reflect price volatility over the next few years as gas prices respond to economic incentives and cycles to ensure sufficient and reliable gas supply.

Gas prices during the decade of the 1990s were stable, fluctuating around $2.00 per Mcf. The price spike of the 2000–2001 heating season was the most dramatic run-up in gas prices in history with prices increasing from their historical low of $2.00 to almost $10.00 per Mcf. This increase in wholesale prices quickly resulted in a significant increase in gas production that expanded the supply of natural gas for the 2001–2002 winter. The resulting increased inventory of natural gas was met with reduced industrial demand because of the prior season's high prices and warmer than normal weather which reduced demand by all customers. Natural gas prices responded to the over supply situation by falling, which reduced not only the price but also the quantity of gas available for the 2002–2003 winter as gas rigs shut down in response to falling prices. As noted in the previous section, the storage of gas across the country was near a five year high at the beginning of the heating season and remained within the five year historical range for the rest of the winter.

The commodity price of natural gas has been increasing all over North America. There are both supply and demand explanations for this. First, aggregate demand for natural gas has been growing and is expected to increase by about 1.4% during 2004[10]. This is being driven by expanding economic growth as the United States enters a post recession phase. Real Gross Domestic Product (GDP) grew 3.9% per year during the first quarter of 2004.[11] Economic growth generally indicates increased natural gas use especially from manufacturing activities. Also, electricity production from gas-fired generation is expected to grow in terms of megawatt capacity by 4.7% in 2004[12].

Second, the North American natural gas markets are changing. The annual volume of natural gas that the U.S. imports from Canada is expected to remain relatively flat for the foreseeable future because of growing Canadian demand for natural gas coupled with diminishing production in Western Canada. Net U.S. exports to Mexico continue to rise and that trend likely will continue through 2006[13].

There are a few other supply concerns affecting the gas markets. Natural gas prices closely trend oil prices. Even though the oil and gas markets are separate, the prices for these two commodities move together because of inter-fuel competition in the industrial and power generation sectors. Thus the recent $40 per barrel world oil price is helping to support the $6 per Mcf gas prices this summer.

[10] From the Energy Information Administration's Short-Term Energy Outlook published June 2004
[11] From the Bureau of Economic Analysis released June 25, 2004
[12] From the Energy Information Administration's Annual Energy Outlook 2004 with Projections to 2025
[13] From the Energy Information Administration's Annual Energy Outlook 2004 with Projections to 2025

Today, roughly 99 percent of the U.S. gas supply comes from traditional land-based and offshore supply areas in the U.S. and Canada. Domestic natural gas production is expected to grow about 0.9% in 2004[14]. Well drilling activities will remain high in 2004 and 2005. However, production levels from existing wells continue to decline which basically negate gains from the increased total number of producing wells.[15] Researchers at the National Oceanic and Atmospheric Administration (NOAA) are forecasting above normal hurricane activity in the Atlantic Ocean for August and September 2004. Hurricanes can disrupt the production of natural gas on off-shore drilling platforms.

Gas demand is projected to increase at an average annual rate of 1.8 percent between 2002 and 2025 primarily because of rapid growth in the electric generation sector. Gas continues to be the fuel of choice for electric capacity additions. The natural gas share of electricity generation is projected to increase from 18 percent in 2002 to 23 percent in 2025, including generation by electric utilities, IPPs[16] and CHP[17] generators.[18]

Today the market is still nervous about gas prices and supply and this concern is likely to continue over the near-term. The gas industry has recently been operating at the tight end of the gas supply curve. As production nears capacity, the price responses to changes in demand or supply intensify. For example, if production is at its peak and demand increases, prices will increase far more than if idle capacity existed. The tight supply situation, gas price volatility, and higher gas prices are expected to persist.

[14] From the Energy Information Administration's Short-Term Energy Outlook published June 2004

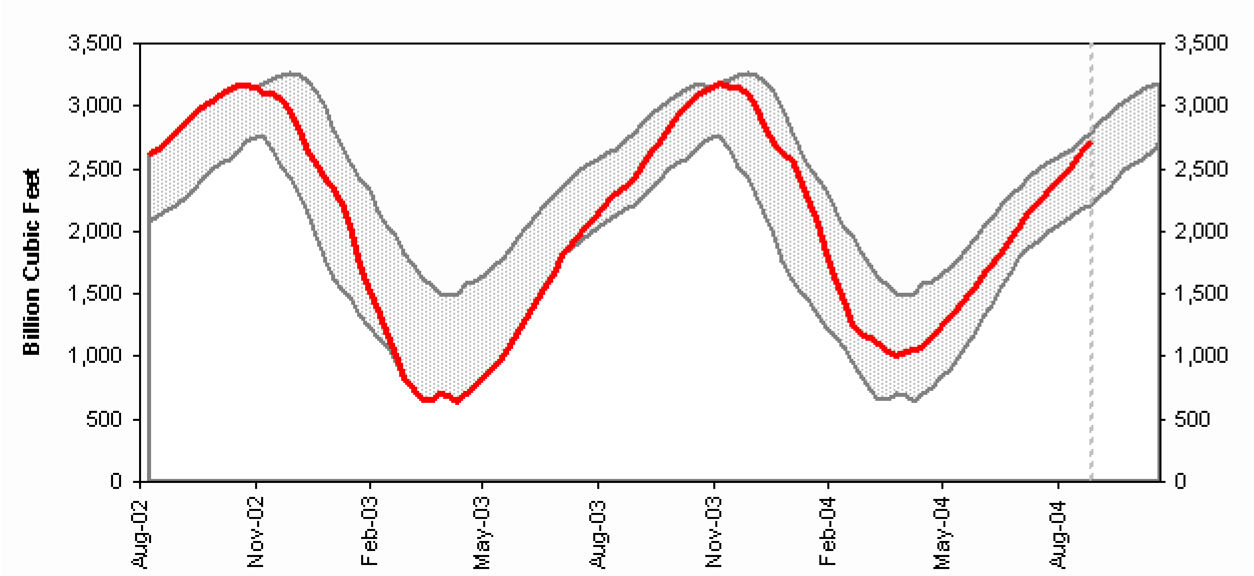
[15] In general, a natural gas well will typically produce less and less gas each year over its useful production life.

[16] Independent Power Producers ("IPPs") are entities other than the electric utility in the area that produce electric power. The term is synonymous with "non-utility generation", also known as "NUG".

[17] Combined Heat and Power ("CHP") means the simultaneous generation of heat and electricity in a single plant. CHP can be used for district heating or industrial processes.

[18] Energy Information Administration's Annual Energy Outlook 2004.

Working Gas in Underground Storage Compared with 5-year Range



Notes: A weekly record for March 8, 2002, was linearly interpolated between the derived weekly estimates that end March 1 and the initial estimate from the EIA-912 on March 15. The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 1999 through 2003.
Source: Weekly storage values from March 15, 2002, to the present are from Form EIA-912, "Weekly Underground Natural Gas Storage Report." Values for earlier weeks are from the Historical Weekly Storage Estimates Database, with the exception of March 8, 2002.

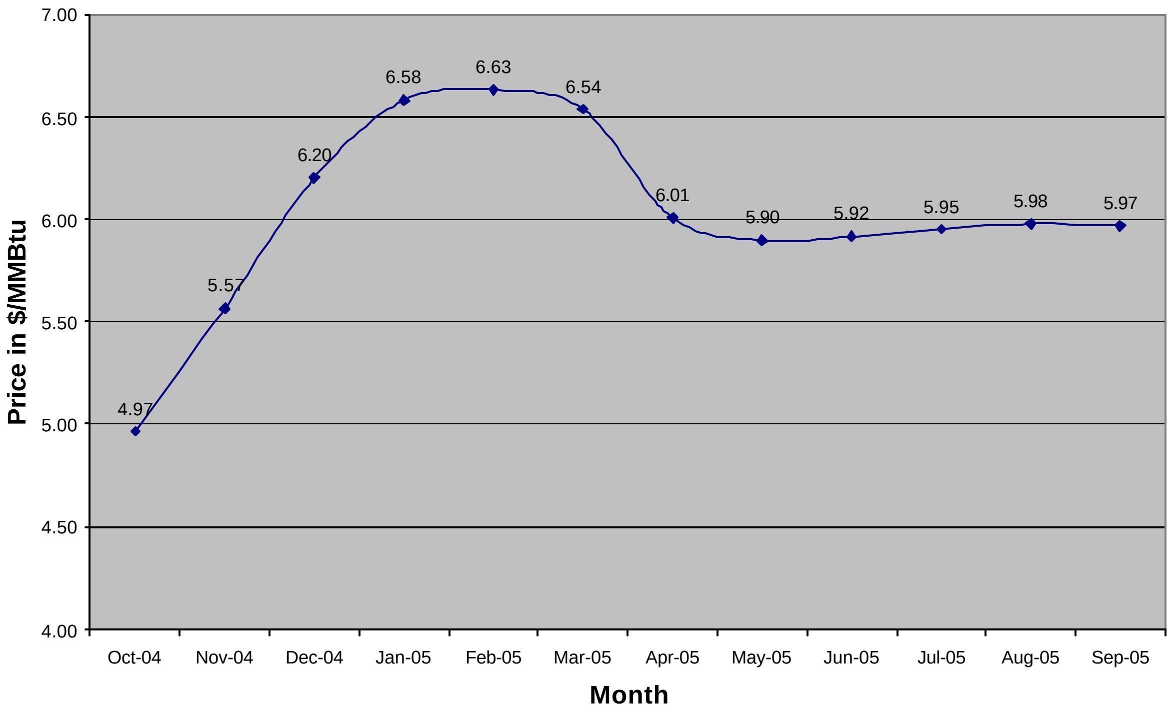
Region	Current Stocks 8/27/04	Estimated Prior 5-Year (1999-2003) Average	Percent Difference from 5 Year Average	Implied Net Change from Prior Week	One-Week Prior Stocks 8/20/04
East Region	1,539	1,482	3.8%	50	1,489
West Region	354	333	6.3%	12	342
Producing Region	802	696	15.2%	19	783
Total Lower 48	2,695	2,511	7.3%	81	2,614

Source: Energy Information Administration: Form EIA-912, "Weekly Underground Natural Gas Storage Report," and the Historical Weekly Storage Estimates Database. Row and column sums may not equal totals due to independent rounding. All volumes are measured in Billion Cubic Feet (Bcf).

Natural gas in storage was near a five year high at the start of the heating season and stayed within the five year historical range for the remainder of the winter. As of August 27, 2004, total working gas is approaching the high-end of the five year range.

As future demand for natural gas grows, it may become necessary to increase the development and utilization of non-traditional natural gas sources such as Alaskan gas, deep off-shore gas, and imported liquefied natural gas. Increasing natural gas supplies will help boost economic development while ensuring more stable prices for natural gas customers.[19]

NYMEX GAS FUTURES PRICES AS OF SEPTEMBER 1, 2004



Commission Actions Addressing Price Volatility, Supply Reliability, and Customer Assistance Programs

Routine Commission Review of Gas Prices and Supply

As part of its normal course of business, the Commission monitors gas prices in the Gas Cost Adjustment (GCA) proceedings[20] for gas utilities under its jurisdiction. The scrutiny within these proceedings by both the Commission and the Office of Utility Consumer Counselor (OUCC) has increased dramatically since the increase in gas price volatility over the last few years. In its orders, the Commission has encouraged utilities to explore innovative ways to control gas prices using strategies such as hedging, fixed and ratable purchases, and efficient use of storage.

In response to the Commission's interest in the issue of gas price volatility, many utilities have begun to include testimony on their price mitigation efforts as part of their normal filings in GCA

[19] Energy Information Administration's Annual Energy Outlook 2004.

[20] A gas cost adjustment (GCA) is an adjustment to effective rates which reflects the fluctuating cost of purchased gas. LDCs are allowed to pass-through the cost of gas and may not profit from this pass-through. The GCA statute may be found at I.C. 8-1-2-42.

proceedings. Information currently being provided by LDCs includes gas procurement strategies, gas purchasing targets by type of contract, storage options, and price projections.

NIPSCO's DependaBill Program

The Commission approved a fixed gas bill (FGB) proposal by NIPSCO for a three-year trial period.[21] This program permits residential and commercial customers to fix their monthly gas bills payable to NIPSCO for an annual period regardless of the change in the price of natural gas or the weather's impact on consumption during a twelve-month period.[22] The FGB was marketed to customers as "DependaBill."

For the initial year of the program, NIPSCO chose a January 1, 2003, starting date and decided to limit enrollment to 1,500 customers. NIPSCO sent marketing materials to all customers who were part of NIPSCO's first two billing cycles[23], which included roughly 30,000 customers. NIPSCO ultimately approved the enrollment of 1,600 customers in the program. Of those 1,600 customers, twelve left the program, in all cases because the customers were moving. One of the conditions of the program is that a customer can be involuntarily dropped from the program if the customer uses 15% more gas than the customer would normally use; however, in no cases was it necessary for this provision to be invoked. Additional usage due to colder weather will not result in any customers being involuntarily dropped.

NIPSCO offered the program to a new group of customers for a program year which ran from August 1, 2003, to July 31, 2004. The company sent out solicitations to 250,000 customers, with a target enrollment of 4,000 to 6,000 and 3,270 actually enrolled. For the year beginning August 1, 2004, NIPSCO expects to send out 365,000 solicitations, with a target enrollment of 3,000 to 4,500. The Order approving the DependaBill program was based on NIPSCO's representation that there would be a limit of 30,000 customers participating in the program.

NIPSCO has filed a petition to amend the Commission's original FGB order.[24] NIPSCO's contract with its unaffiliated partner in the FGB program, WeatherWise, was terminated in the fall of 2003. Up to that point, WeatherWise provided direct marketing for the FGB program and devised individualized quotes for interested customers. WeatherWise was unable to perform its contractual obligations due to financial problems so NIPSCO took over those roles during the 2003-2004 heating season. The original Order did not provide for any entity other than WeatherWise to be compensated for

[21] Cause No. 42097, approved July 3, 2002, approved a Fixed Gas Bill service offering for NIPSCO. The Company changed the name of the program to DependaBill prior to actual implementation.

[22] This service differs from NIPSCO's Budget Billing Plan because it does not require a "true-up" at the end of the annual period, and from its Price Protection Plan, because bills still vary based on consumption even though a unit price for an annual period has been fixed.

[23] NIPSCO has 21 billing cycles per month that correspond to the 21 workdays of the month. NIPSCO has approximately 600,000 customers, so the first two billing cycles include roughly 30,000 customers. With 1,600 customers signing up for DependaBill, that is an enrollment rate of approximately 5 percent.

[24] Cause No. 42097, Petition to Amend Order, filed May 21, 2004. An Evidentiary hearing is set for November 3, 2004.

marketing and related services. That Order also only allowed customers to sign-up using their written signature. NIPSCO would like the Order to be amended to allow for electronic enrollment.

NIPSCO's Gas Cost Adjustment (GCA)

NIPSCO, which has been using a monthly GCA since 1999, experienced high volatility in its gas prices for its March 2003 Commodity filing. The natural gas price spike of late February 2003 peaked during the week when NIPSCO needed to lock in prices for the upcoming month. As a result, NIPSCO's March Commodity filing showed a 28% increase for a typical residential customer's bill, compared to February's bills.

The OUCC determined that this was an unacceptable increase. Additionally, the OUCC observed that, as of February 2002, NIPSCO had already increased its gas bills for residential customers by nearly 60%. The proposed March rate hike would have increased customer bills to levels more than double comparable bills in 2002. The OUCC also alleged that NIPSCO had not provided reasonable price volatility mitigation to its GCA customers as part of its standard, regulated utility service. The OUCC requested that the Commission block NIPSCO's implementation of the March Commodity factor. The Commission ultimately allowed the factor to be implemented on an interim basis, while the OUCC's objection was litigated. A final decision on the March 2003 Commodity filing was reached on September 10, 2003.

The Commission determined that NIPSCO's purchasing and storage practices warranted a $3.8 million disallowance, which was refunded to customers during the November 2003 through January 2004 winter period. Litigation revealed that, for the volatile month of March 2003, NIPSCO had no fixed-price contracts which could have reduced the volatility passed on to customers and the calendar-year storage pricing methodology provided minor cushion from the price spike. NIPSCO was ordered to transition to a new storage pricing methodology for GCA purposes, which would center pricing on a regulatory storage accounting year of April 1 to March 31. This should have the effect of more closely aligning storage injection and withdrawal pricing.

NIPSCO's GCA 5, which covers the twelve months beginning November 2003, has revealed positive changes as a result of the litigation and final orders in GCA 4. Some of these are: 1) improved communication and information exchange between NIPSCO, the OUCC's auditors, and Commission Staff; 2) ongoing meetings between the Parties and Commission Staff, which have resulted in significant improvements to monthly and annual GCA filings; and 3) increased volatility mitigation, which has been reflected in customers' bills. A proposed settlement agreement which promises further improvements in communication, refinements to NIPSCO's Gas Cost Incentive Mechanism and up to $3.8 million being returned to GCA customers over twelve-months was approved by final Commission order on August 18, 2004. .[25]

[25] Cause No. 41338 GCA 5; Stipulation and Settlement Agreement filed June 11, 2004; Evidentiary hearing June 18, 2004

Natural Gas Forum 2004

On June 21 and 22, 2004, the Commission conducted the annual Natural Gas Forum (Forum). The Commission, recognizing the volatility in gas prices for the upcoming winter and the immediate need to address high gas bills, used the Forum to assess the following: 1) what Indiana utilities have done to secure gas supply and control the price of gas for the upcoming winter heating season, 2) what future actions utilities intend to take to mitigate the effects of higher gas costs and price volatility on customers, and 3) what joint efforts the OUCC, IURC, and LDCs can engage in to inform the public about current market conditions for gas and actions customers can take to maintain better control over their gas bills. Citizens, NIPSCO, Northern Indiana Fuel and Light Company, Ohio Valley Gas Corporation, and Vectren made presentations and participated in the Forum. The Transportation Safety Institute presented issues regarding pipeline safety matters. The LDCs that participated in the Forum provide service to the vast majority of gas customers in Indiana. While there can be some company-specific differences, particularly with smaller companies, we believe the information provided has applicability for the state as a whole.

All participating LDCs indicated that the volatility in gas prices should continue throughout the winter heating season with gas prices expected to be at least as high as last year. Demand is projected to increase more than 1% in 2004 and economic growth is expected to exceed 4%.[26] Production is expected to remain relatively flat.[27] Drilling efforts continue but gas production has not increased due to an increased level of well depletion.[28] With restriction of natural gas reserves, new supply and the need for increased access will need to come from new sources. Some suggested short to mid-term solutions include the expansion of LNG, increasing production in deeper waters in the gulf, increasing other fuel sources for electric generation, and conservation.[29]

The presentations from all participating LDCs emphasized the necessity of portfolio diversity to secure gas supply and control the price of gas. Each maintains a program that includes the purchasing of gas futures fixing a portion of gas purchases at a given rate. Rather than relying on the spot market, where gas prices change constantly and can vary radically, LDCs are increasing the amount of gas purchased under either fixed price or hedged contracts. Portfolio management of gas procurement increases the reliability of gas supply and secures gas at known prices, which decreases the LDCs exposure to price volatility and levelizes the prices charged to customers.

All utilities cautioned, however, that price volatility mitigation does not guarantee that customers will be charged the lowest prices for gas. If gas prices fall after the execution of a contract for controlling the price and volume of gas, customers may end up paying a premium for more stable prices. The Commission encourages utilities to mitigate price volatility using these and other measures while at the

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[26] As presented by Citizens Gas and Coke Utility before the Indiana Utility Regulatory Commission on June 22, 2004, p. 9.
[27] Ibid.
[28] As presented by Northern Indiana Public Service Commission before the Indiana Utility Regulatory Commission on June 21, 2004, pp. 7-8.
[29] As presented by SIGECO and Indiana Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc. before the Indiana Utility Regulatory Commission on June 21, 2004, p. 13.

same time recognizing that the resulting cost of gas may end up exceeding future spot prices.[30] Stable gas prices in a volatile market are generally desirable and might be considered worth the payment of a slight premium. Conversely, if gas costs continue to go up over the heating season, customers will benefit from lower gas costs locked in earlier and realize savings over the winter heating season. Of course, all utilities must continue to demonstrate that their purchasing strategy was reasonable and prudent given the best information available at the time, and that all alternatives have been considered.[31]

Gas held in underground storage has historically served to increase system reliability and reduce winter gas costs. Typically, storage gas is used during the winter when prices are high and replenished in the summer when prices are low. At the Forum, all LDCs reported that their schedules for filling gas storage for the winter are on target. The Commission was assured by Forum participants that storage will be full at the beginning of the 2004–2005 heating season. However, gas industry dynamics have conspired to diminish the price hedge that storage has historically provided. Summer gas rates have increased because of greater demand for gas during the summer by electric generators and the threat of inadequate gas supplies for the coming winter. Even though storage should be full and continue to bestow the benefits of system reliability and control over gas purchasing (LDCs can avoid seasonal high prices by using their storage gas), the significant cost advantage it historically provided has been reduced.

The expectation for even higher bills is cause for great concern because of the significant ramifications for Indiana residents and the State's economy. Vectren anticipates a significant effect on low-income customers who already struggle to pay and a widening of the number of customers who experience difficulty paying their bills. For each $1.00 per Dth increase in the commodity cost of gas, Vectren estimates an approximate annual increase of $100 for the average residential customer and an approximate annual increase of $350 for the average commercial customer.[32] Like commercial customers, industrial customers' costs of operations will increase which threatens their growth and expansion opportunities, and the economic recovery of the State.

All utilities are engaging in customer education and information campaigns to prepare customers for next winter, minimize shutoffs and expand assistance efforts.[33] Utilities are warning their customers of the expected seriousness of the gas pricing situation and offering advice on self-help measures to control their gas bills. Actions customers can take include but are not limited to conservation by dialing down the thermostat, home weatherization, and going on the budget payment plan.

Finally, LDC participants outlined their short and long term efforts to assist customers with bill payment. Customers are encouraged to call their local gas utility to discuss payment problems and work out mutually beneficial billing solutions. LDCs will advise customers regarding potential financial

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[30] Southern Indiana Gas and Electric Company, Cause No. 37366 GCA 78, approved April 23, 2003.
[31] *Ibid.*
[32] As presented by SIGECO and Indiana Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc. before the Indiana Utility Regulatory Commission on June 21, 2004, p. 25.
[33] Utilities are using bill inserts, public meetings, the media and their web sites to impart information on higher winter heating bills to customers.

assistance.[34] By adopting the measures and strategies explored at the Forum, it is the hope of the Commission that the strain on the budget of Indiana's citizens and industries that use natural gas can be minimized and manageable.

Customer Deposit Rulemaking

On June 1, 2004, the Commission published a Notice of Intent to Adopt a rulemaking on customer rights and responsibilities for all utility industries. The Notice of Proposed Rulemaking was issued by the Commission on July 21, 2004.[35] All utility industries are included in this rulemaking. However, the rulemaking is focused on the gas utility industry in particular based upon the generally higher and more volatile price for natural gas. Provisions of the Commission's rules governing the relationship between gas utilities and customers in the areas of creditworthiness, deposits, disconnections, payment arrangements and reconnection of service, the handling of customer complaints, and estimated bills have been reviewed and updated in the proposed rule. A summary of the major areas included in the proposed rule for gas customers would cover:

- Creditworthiness: The creditworthiness rules have been simplified and credit scoring systems will be allowed. Utilities may no longer use unpaid bills as leverage against customers for periods exceeding four years. The unpaid bills must be either collected or written off.
- Deposits: The amount of required deposits has been reduced for gas customers from 1/3 of estimated annual billings to 1/6. The amount of the deposit should be based on regulated utility service charges only and deposits will be automatically refunded upon termination of service.
- Disconnections: These revised guidelines expand upon previous language in the rule governing when disconnections may occur and how they should be carried out.
- Payment Arrangements and Reconnection of Service: The amount of deposit customers must pay in order to be reconnected has been changed to allow customers to pay the deposit in equal installments over three months.. During the winter moratorium on disconnections for nonpayment, gas and electric customers can be reconnected by paying 20% of the amount past due and 20% of any deposit due, with the balance being paid off over a minimum of three months.
- Home Energy Assistance: No substantive changes were made to these rules. They discuss the winter moratorium period and eligibility for heating assistance programs.
- Customer Complaints to the Utility and to the Commission: These rules outline what should be considered a "complaint," when it should be considered to be received, and the steps a utility must take when a customer complaint is received. Utilities must keep records of complaints and their resolutions and make these records available to the Commission. If a complaint cannot be satisfactorily resolved by the utility, it may be addressed with the

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[34] Assistance Programs include LIHEAP (Low Income Home Energy Assistance Program) federal funds, Share the Warmth, and low income weatherization.

[35] Notice of Proposed Rulemaking (IURC RM #04-02); Public hearing scheduled for September 22, 2004, at 10:30 a.m., in Training Center Room 10, of the Indiana Government Center South.

IURC's Consumer Affairs Division. Guidelines are provided for the steps required once a complaint is filed with the IURC.

- Estimated bills: This section covers when, how often, and why bill estimations may be used.

Other Gas Issues Affecting Indiana

GCA Timeframes–semi-annually, quarterly, and monthly

The majority of Indiana's smaller LDCs continue to file traditional quarterly GCA petitions. Only two companies, Kokomo Gas and Fuel Company and Northern Indiana Fuel & Light Company, continue to implement gas cost adjustments on a semi-annual basis.

Currently, two LDCs, NIPSCO and Valley Rural Utility Company, use a monthly GCA factor with an annual hearing to discuss important issues pertaining to the previous and upcoming years, to true-up any under- or over-estimated costs, and to present known demand costs for the upcoming year. NIPSCO's and Valley Rural's GCA mechanisms, approved under the Alternative Utility Regulation statute[36], allow monthly flexing up or down based on prevailing market conditions.[37] In addition to the annual hearing requirements, both LDCs are required to file monthly informational filings with the Commission showing commodity prices and GCA factors to be implemented for the upcoming month. NIPSCO, an investor-owned LDC, files quarterly earnings information. Valley Rural Utility Company, a not-for-profit, recovers its incremental gas costs over base rates on a monthly basis as approved in its Alternative Regulatory Plan (ARP). Recoverable costs are subject to a cap, and will be subject to review in an annual gas supply proceeding that addresses the components of gas supply for the upcoming year and seeks final approval of the gas supply costs charged during the preceding twelve months. As of April 2004, the Company was providing service to 189 customers.

Three of Indiana's major LDCs continue to file quarterly GCAs, but are allowed to adjust their approved GCAs monthly. IGC and SIGECO, both subsidiaries of Vectren Energy Delivery of Indiana, are allowed to "flex," or adjust, their GCA factors down from Commission approved maximum factors, or caps, once a month in an effort to more closely reflect current gas prices. These flex-down mechanisms are approved on a cause-by-cause basis. Additionally, Citizens petitioned to file quarterly with monthly adjustments to its GCA factors on July 26, 2002.[38] Citizens may flex its monthly GCA factor up or down, with a $1.00 per Dth maximum flex. The mechanism was initially approved for a test period of one-year. On April 29, 2003, representatives of Citizens, the OUCC, and the Commission Staff met to review the performance of the GCA monthly flex mechanism. As a result of that meeting, the parties filed a report to the Commission on August 15, 2003, and an amended settlement agreement on the GCA flex issue on October 9, 2003. The Commission subsequently issued an order on March 17, 2004, which extended use of the flex mechanism through August 2005 (GCA 86). With the approval of this change for Citizens, the majority of gas bills rendered in Indiana reflect GCA factors that change monthly.

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[36] Indiana Code § 8-1-2.5 Alternative Utility Regulation

[37] Cause No. 41338 ARP, NIPSCO; Approved 12/1/1998 and Cause No. 42115 Certificate of Need and ARP, Valley Rural Utility Company; Approved 5/8/2002

[38] Cause No. 37399 GCA 75, Citizens Gas & Coke Utility, approved September 4, 2002.

Gas Cost Incentive Mechanisms

A Gas Cost Incentive Mechanism (GCIM) provides risks and rewards to LDCs for gas supply acquisition performance compared to a market standard (benchmark). Benchmark prices reflect natural gas commodity prices for geographic locations representative of the supply source where the gas was purchased, and are usually calculated monthly. The benchmark price is then divided by the actual amount of gas purchased to determine the benchmark dollars. If an LDC's actual natural gas commodity purchases are above or below the benchmark dollars, predetermined percentages of the positive or negative differentials are shared among the utility and its customers. For example, if the actual gas purchases are slightly below the benchmark dollars, a higher percentage of the savings goes to the customers; however, if the actual gas purchases are a greater percentage below the benchmark dollars, a higher percentage of the savings differential is shifted to the LDC. This works similarly on the other side of the benchmark level. The customers absorb costs that are only slightly higher than the benchmark; however, if costs exceed the benchmark by a greater amount, a higher percentage of the differential is shifted to the LDC.

NIPSCO has had a GCIM in place since 1997, which was approved as part of its ARP.[39] The proposed Stipulation and Settlement Agreement in Cause No. 41338 GCA 5 enhances NIPSCO's GCIM and includes an extension of NIPSCO's ARP through March 2005. The extension will provide time for parties to negotiate future terms of the ARP, which could include a more thorough modification of NIPSCO's GCIM. IGC, SIGECO and Citizens have implemented GCIMs as part of an ARP approved on July 24, 2002.[40]

Citizens, Indiana Gas, and SIGECO Propose Universal Service Plan

On March 4, 2004, Citizens, Indiana Gas, and SIGECO filed their joint petition for approval to implement a pilot "Universal Service Program." The proposed Universal Service Plan is intended to assist eligible and qualifying low-income customers by providing them with a significant reduction in the payment of their gas bills. These bill reductions will be based on tiers that take into account the additional burdens placed on those customers whose income level falls well below the poverty guidelines. The program will be based on a 2-year pilot and have an enrollment of approximately 21,200 for Indiana Gas and SIGECO and approximately 16,000 for Citizens.

Eligible low-income customers will be enrolled in the program by existing community action agencies through the LIHEAP application enrollment process. The net bill for participating Indiana Gas and SIGECO customers will be a 45%, 50%, or 55% reduction in their residential gas service bill. The discount for participating Citizens customers will be 35%, 40%, or 45%. These customers will still be protected under the winter service cut-off moratorium. LIHEAP funds and existing support programs will go towards funding the proposed program. Indiana Gas and SIGECO will fund the remaining balance by a per unit charge on residential, commercial, and industrial customers. Citizens will fund the remaining balance through a contribution from its Customer Benefit Distribution. The pilot program was approved by final order of the Commission on August 18, 2004.

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[39] Cause No. 40342, Northern Indiana Public Service Company, approved on October 8, 1997.
[40] Cause No. 42233 ARP which has been consolidated with Cause Nos. 37394 GCA 50-S1 and 37399 GCA 50-S1.

SIGECO's Demand Side Management Program

SIGECO has utilized demand side management (DSM) as a means of reducing customer load and system demand for its electric utility for several years. The Commission has approved some of these programs and has approved the deferral of most of the costs for subsequent rate recovery in a specific manner. On April 15, 2003, SIGECO filed a petition in Cause No. 42418 to gain Commission approval of a DSM program for its electric utility and for the first time, its gas utility.

Generally, DSM programs are attempts to meet load growth using methods such as conservation and load management rather than simply buying more natural gas and pipeline capacity. This proposal is the result of a cooperative process between SIGECO, the OUCC, and the Citizens Action Coalition of Indiana (The Parties). The Parties will each appoint a representative to an advisory board who will select and oversee the activities of a non-utility independent third party administrator (the Administrator). The Administrator will be in charge of designing and implementing the DSM program. This represents the first time the Commission has been presented with a DSM program involving a third party administrator; in all other DSM programs approved by the Commission, the utility acted as the administrator.

Through developing partnerships with private area businesses and contractors, the Administrator will offer energy conservation and efficiency programs to customers. The DSM administrator will be provided with $3 million per year ($2.5 million for electric and $500,000 for gas) by SIGECO over the next three years and SIGECO will recover those expenditures through a tracking mechanism over the next ten years. The electric and gas costs will be recovered in separate tracking mechanisms. SIGECO also sought approval to recover prior DSM electric costs through the electric DSM tracker. Customers who make qualified efficiency investments also will be provided with rebates as an incentive, the cost of which will not be recovered in rates. Additionally, SIGECO will spend $100,000 in each of three years to educate customers regarding the DSM program, usage behavior, the rebate program and the higher cost of service during peak periods. These funds will not be recouped through the DSM trackers.

On October 8, 2003, the Commission approved, in part, a settlement between the parties in Cause No. 42418 to proceed with the proposed DSM program. The Commission commended the Program. However, the Commission denied the portions of the Settlement that provide for the recovery of SIGECO's past and deferred electric DSM program costs via the electric DSM tracker and indicated those costs should be reviewed in the context of SIGECO's next rate case. SIGECO requested a rehearing of the Commission's October 8, 2003, decision.

The Commission granted the request for rehearing on December 3, 2003. The parties filed evidence to support SIGECO's recovery of the electric DSM deferred costs via the electric DSM tracker and submitted a joint settlement agreement. A hearing was held on February 17, 2004. On July 21, 2004, the Commission issued its Order on rehearing which affirmed its decision contained in the October 8, 2003, Order and indicated it would initiate an investigation into DSM programs on a state-wide basis. On July 28, 2004, the Commission initiated such an investigation through its order in Cause No. 42693. The investigation is expected to include both electric and gas utility DSM programs.

Pipeline Safety Activity

President Bush signed the Pipeline Safety Improvement Act of 2002 (the "Act") on December 17, 2002. Several provisions included in the Act have impacted and will continue to impact the State of Indiana. With improved public safety as the intended outcome, additional efforts are being committed by both pipeline operators and the IURC to ensure compliance with the law.

The law mandates that all operators of natural gas transmission lines have an integrity management program in place for high consequence areas by December 2004.[41] Indiana's intrastate gas companies operate 1,886 miles of transmission pipeline. Not all of these pipelines are located in high consequence areas, as that term is defined in the rule. The impact of a gas pipeline rupture varies based on its size, operating pressure and proximity to people. The rule requires operators to use these factors, along with other factors, including the calculation of heat-impacted zones, to identify high consequence areas.

For pipelines located in high consequence areas, baseline integrity assessments (determining the current physical condition of pipelines) began in June 2004 and must be completed December 2007 or 2012, depending on the facility's location, pressure and diameter. Assessments may be made by utilizing in-line inspections (pigging), hydrostatic pressure testing, or direct assessment[42]. It is anticipated that gas transmission operators will dedicate significant resources in order to comply with the regulations. Costs will be incurred for identifying pipeline segments in high consequence areas, setting up a framework for the company's program, conducting a baseline assessment of affected pipelines, conducting periodic assessment and evaluation, evaluating automatic shutoff and remotely controlled valves, data integration and remedial action. The cost to gas utilities will be dependent partially upon the baseline assessment timeframe, the extent to which Indiana's facilities can be internally inspected, and other factors.

Indiana's gas utilities and, in turn, its customers will also be affected by the manner in which interstate gas transmission operators conduct their integrity management programs. Unless adequate time is allowed and the assessment process is carefully managed, flow restrictions can significantly impact gas supply and cost to customers. There exists the potential for critical supply interruptions, as well, as this law applies to interstate transmission companies that serve the Indiana utilities. In Indiana there are over 5,000 miles of interstate gas transmission pipelines.

The enforcement of the Integrity Management rule will require additional training for the IURC's Pipeline Safety Division. The Transportation Safety Institute, which is the training agency within the U.S. Department of Transportation, is developing a series of courses, which inspectors are to complete before conducting Integrity Management inspections. Federal protocols are under development and will be used during the inspection process. Although Indiana's intrastate transmission facilities do not

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[41] The U.S. Department of Transportation's Office of Pipeline Safety (OPS) issued a final integrity management rule on December 15, 2003, with updates published April 6, 2004, and May 26, 2004.

[42] Direct Assessment is a method that utilizes a process to evaluate certain threats (e.g., external corrosion, internal corrosion, and stress corrosion cracking) to a pipeline's integrity. It includes data gathering, indirect and direct examination of the pipeline, and post assessment evaluation.

represent the bulk of jurisdictional piping for the Pipeline Safety Division, the nature of the inspections will require the Division to dedicate considerable resources to integrity management enforcement due to the complexity of the regulation.

The Pipeline Safety Act also addresses pipeline outreach programs. Among other things, it requires operators to review and revise existing public education programs. The first step in this process occurred in December 2003 when operators conducted a self-assessment of their public education plans and submitted the assessments to the IURC Pipeline Safety Division and OPS headquarters in Washington. A National Standard (API Standard RP 1162) has been developed to address this topic and will be incorporated by reference into federal pipeline safety regulations. This Standard sets forth specific requirements regarding the message, methodology and frequency of communication with target audiences. The Pipeline Safety Division will enforce this as part of its inspection process.

The Act also requires the Secretary of Transportation to encourage the adoption of practices set forth in the best practices report entitled "Common Ground."[43] Indiana's Pipeline Safety Division is taking an active role in following through with the requirements of these provisions. It continues to work with state and federal liaisons and the Board, staff, and members of the Indiana Underground Plant Protection Services to encourage the adoption of best practices and involvement in the Common Ground Alliance. The Division intends to do everything in its power to develop and strengthen Indiana's underground protection laws and damage prevention programs, as third-party damage continues to be the leading cause of pipeline accidents, both statewide and nationwide.

The Act includes additional requirements for Indiana's gas operators. It requires all operators to develop and complete qualification of pipeline personnel programs (Operator Qualification Programs); and requires regulators to conduct reviews of such programs by December 2005. Inspections of the Operator Qualification programs have begun, and data gathered during the inspection process is being entered into a federal OPS database. This data will be used to develop a report for Congress concerning the progress of Operator Qualification Programs. In accordance with the mapping provision of the Act, natural gas transmission operators provided data to the National Mapping System and will update this information as necessary. Finally, the Act required the Secretary of Transportation to work with the Federal Communications Commission, facility operators, excavators, and one-call notification systems for the establishment of a nationwide toll-free 3-digit telephone number system to be used by state one-call programs. The Federal Communications Commission recently issued a Notice of Proposed Rulemaking (NPRM) seeking comment on various abbreviated dialing arrangements that could be used to comply with this provision. The NPRM tentatively concludes that 811 should be used as the national One Call notification number. The costs to implement three-digit dialing for One Call are still being determined.

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[43] The Common Ground study was developed in response to a directive from Congress to the US DOT. The directive required the development of best practices for preventing damage to underground facilities and assuring their safe operation. The result was the comprehensive Common Ground study and the subsequent establishment of the Common Ground Alliance – a non-for profit organization that fosters communication and the adoption of best practices.

Competitive Initiatives in Natural Gas

National Overview

Since the implementation of the Natural Gas Policy Act of 1978, Congress began a process that ended federal control over the price of gas at the wellhead. This process also set in motion a series of public policy changes by the Federal Energy Regulatory Commission and state regulators that has culminated in "customer choice" programs in the natural gas industry.

Natural gas choice is similar to choosing a long distance telephone company. The local utility continues to own and maintain the pipes that deliver the gas service to consumers' homes or businesses, but consumers can choose the company that provides their natural gas. In today's competitive market, suppliers can offer a variety of prices, incentives or services to gain business. Therefore, customers have the opportunity to comparison shop for the best deal, just like they do when they buy a car, home, or their weekly groceries. Since 1995, several states have enacted legislation or rules that allow residential customers and small commercial customers to purchase gas from someone other than the local gas company.

Currently, choice programs are operating in nineteen states and the District of Columbia. About 3.9 million residential customers participate in choice programs. Participation rates vary dramatically across programs, ranging from those that attract few customers to participation rates of 30-50 percent. Some states have expanded their programs to include more eligible customers while others have died, strived to survive or simply reached a plateau.

Nationally, there has been a decline in the number of marketers over the past few years. The increase in gas prices in the winter of 2000–2001, the financial problems of energy trading companies, and the increased difficulty of marketers to make a profit all contributed to the reduced number of marketers. The gas business is a low profit-margin business where marketers are selling a commodity to a mass market. Marketers must purchase gas and transportation in the same markets as LDCs. Some marketers have discovered that customer service and marketing costs cut too deeply into their profits.[44]

Choice programs continue to evolve over time as circumstances change. These programs still provide a challenge to LDCs, marketers, and regulators as they change in size and scope in response to market realities over which no one has control. The learning process and reconfiguring of choice programs can be expected to continue.

[44] The National Regulatory Research Institute, *Survey on the Features and Regulatory Oversight of Gas Choice Programs*, NRRI 03-02, February 2003, pp. 1-2.

Status of Customer Choice in Indiana

NIPSCO's Customer Choice Program

The Commission approved NIPSCO's "Choice" program in its Order of October 8, 1997, in Cause No. 40342. The utility began phasing in its customer choice program in April 1998. The eligibility numbers increased from 50,000 residential and 1,500 business customers to include the entire customer base of 602,000 and 50,000, respectively. The Choice program's enrollment caps are 150,000 residential customers and 20,000 commercial customers. NIPSCO estimates that all of its customers will have access to unbundled service by January 1, 2005.

The company reports that participation dropped substantially over the 2000–2002 time period, with more than 12,000 residential customers enrolled in July 2000, but only 4,766 residential customers in September 2002 after the only active supplier stopped its customer enrollment activities. Nationally during this time, the growth rate for residential customers that had access to choice programs was slowed due to the saturation of prime markets, waning marketer interest and volatility in the natural gas and electricity markets. NIPSCO made a concerted effort to revitalize the program in late 2002 that led to three new suppliers entering the program. As of April 2004, almost 50,000 customers (mostly residential but some commercial as well) were enrolled and seven suppliers were participating, although two of the marketers were not accepting any new residential customers.

TABLE 2

STATUS OF NIPSCO CHOICE PROGRAM
As of April 2004

Customer Class	Total Customers 12/31/2003	Enrollment Caps for Choice Program		Participating		
		Cap	Percentage of 2003 Total	Total	Percentage of Eligible Customers	Percentage of Total Customers
Residential	602,000	150,000	24.9%	43,875	29.3%	7.3%
Business	50,000	20,000	40.0%	6,002	30.0%	12%
Total	652,000	170,000	26.1%	49,877	29.3%	7.7%

Citizens' Alternative Regulatory Plan

Effective June 1, 2003, the Commission approved an Alternative Regulatory Plan for Citizens. The utility cited an increasingly competitive energy environment in which market forces have replaced traditional regulation as the primary reason for the change. Implementation of its unbundled tariff will result in most commercial and industrial customers being able to choose their gas supplier, with Citizens remaining one of the supplier choices. Key elements of Citizen's proposal include: 1) the phasing in of new unbundled services, 2) affiliate guidelines that serve as ethical codes of conduct between the utility and other third-party suppliers, 3) Citizens acting as the supplier of last resort, 4) new service offerings for third-party suppliers, 5) no increase in its current rates, and 6) immediate service changes for large commercial and industrial users using over 50,000 Dth annually in the first year. Currently, customer choice is not available to Citizens' residential customers, although the unbundled tariff and rate design will make its implementation in the future much easier.

COMBINED ANALYSIS OF GAS SALES DATA

CITIZENS GAS, INDIANA GAS, NIPSCO, & SIGECO

Total Sales By Class (1,000 Dth)	2003	2002	2001
Residential	141,561	142,848	132,159
Commercial	63,501	58,252	53,828
Industrial	17,441	18,065	18,993
Other	5,579	6,397	9,861
Total	**228,082**	**225,562**	**214,841**
Total Transportation By Class (1,000 Dth)			
Residential	4,914	1,476	1,238
Commercial	16,882	17,894	11,084
Industrial	198,991	206,996	202,316
Other	1,871	6,043	4,880
Total	**222,658**	**232,409**	**219,518**
Total Throughput By Class (1,000 Dth)			
Residential	146,474	144,324	133,397
Commercial	80,383	76,146	64,912
Industrial	216,432	225,061	221,309
Other	7,449	12,440	14,741
Total	**450,738**	**457,971**	**434,359**
Percent Transportation to Throughput			
Residential	3.35%	1.02%	0.93%
Commercial	21.00%	23.50%	17.08%
Industrial	91.94%	91.97%	91.42%
Other	25.11%	48.58%	33.10%
Total	**49.40%**	**50.75%**	**50.54%**

ANALYSIS OF GAS SALES DATA FOR 2001, 2002 & 2003

CITIZENS GAS AND COKE UTILITY

	2003	2002	2001
Revenues By Customer Class			
Residential	$ 211,384,956	$ 176,765,066	$ 213,914,885
Commercial & Industrial	120,607,508	91,663,893	118,341,083
Other	2,056,853	3,439,265	(16,664,765)
Totals	$ 334,049,317	$ 271,868,224	$ 315,591,203
Sales By Customer Class in Dth			
Residential	24,725,447	24,130,546	22,216,277
Commercial & Industrial	16,754,624	15,910,105	14,609,790
Other	4,328,071	-	-
Totals	45,808,142	40,040,651	36,826,067
Revenues Per Dth			
Residential	$ 8.5493	$ 7.3254	$ 9.6287
Commercial & Industrial	$ 7.1985	$ 5.7614	$ 8.1001
Other	$ 0.4752	$ -	$ -
Average Rate	$ 7.2924	$ 6.7898	$ 8.5698

INDIANA GAS COMPANY, INC.

	2003	2002	2001
Revenues By Customer Class			
Residential	$ 439,108,387	$ 350,567,161	$ 408,937,121
Commercial & Industrial	173,232,908	138,229,744	173,352,672
Other	10,348,843	17,165,239	(30,886,857)
Totals	$ 622,690,138	$ 505,962,144	$ 551,402,936
Sales By Customer Class in Dth			
Residential	48,144,000	45,041,000	41,719,000
Commercial & Industrial	20,773,000	20,062,000	21,649,000
Other	-	-	-
Totals	68,917,000	65,103,000	63,368,000
Revenues Per Dth			
Residential	$ 9.1207	$ 7.7833	$ 9.8022
Commercial & Industrial	$ 8.3393	$ 6.8901	$ 8.0074
Other			
Average Rate	$ 9.0354	$ 7.7717	$ 8.7016

NORTHERN INDIANA PUBLIC SERVICE CO.

Revenues By Customer Class	2003	2002	2001
Residential	$ 584,104,222	$ 469,273,275	$ 577,297,238
Commercial & Industrial	348,415,891	224,251,029	287,919,725
Other	10,979,965	18,436,829	45,321,200
Totals	$ 943,500,078	$ 711,961,133	$ 910,538,163
Sales By Customer Class in Dth			
Residential	60,236,514	65,114,972	59,653,000
Commercial & Industrial	38,817,284	36,167,077	32,349,000
Other	1,243,411	6,392,301	10,466,000
Totals	100,297,209	107,674,350	102,468,000
Revenues Per Dth			
Residential	$ 9.6968	$ 7.2068	$ 9.6776
Commercial & Industrial	$ 8.9758	$ 6.2004	$ 8.9004
Other	$ 8.8305	$ 2.8842	$ 4.3303
Average Rate	$ 9.4070	$ 6.6122	$ 8.8861

SOUTHERN INDIANA GAS & ELECTRIC CO.

Revenues By Customer Class	2003	2002	2001
Residential	$ 69,449,674	$ 64,421,116	$ 69,772,477
Commercial & Industrial	33,786,368	28,147,654	31,898,035
Other	52,654	65,470	102,060
Totals	$ 103,288,696	$ 92,634,240	$ 101,772,572
Sales By Customer Class in Dth			
Residential	8,454,811	8,561,003	8,570,921
Commercial & Industrial	4,597,173	3,774,739	4,213,115
Other	7,221	407,160	(604,580)
Totals	13,059,205	12,742,902	12,179,456
Revenues Per Dth			
Residential	$ 8.2142	$ 7.5249	$ 8.1406
Commercial & Industrial	$ 7.3494	$ 7.4568	$ 7.5711
Other	$ 7.2918	$ 0.1608	$ (0.1688)
Average Rate	$ 7.9093	$ 7.2695	$ 8.3561

RESIDENTIAL GAS BILLS AS OF JANUARY 1, 2004 RANKED HIGHEST TO LOWEST AT 200 THERMS				
Rank	**Utility Name**	**150 Therms**	**200 Therms**	**250 Therms**
1	Ohio Valley Gas Corp. (ANR) * (2)	$ 172.53	$ 225.70	$ 278.88
2	Ohio Valley Gas, Inc. *	$ 170.89	$ 223.52	$ 276.15
3	Valley Rural Utility Company (3)	$ 167.95	$ 220.35	$ 272.75
4	Ohio Valley Gas Corp. (TXG) *	$ 168.39	$ 220.18	$ 271.98
5	Midwest Gas Corp. (Peoples) (4)	$ 166.18	$ 216.02	$ 265.85
6	Lawrenceburg Gas Co. (Rate G-1) *	$ 164.74	$ 213.09	$ 261.44
7	Lawrenceburg Gas Co. (Brookville) *	$ 162.67	$ 211.84	$ 261.02
8	South Eastern Indiana Gas Co.	$ 161.20	$ 211.19	$ 261.18
9	Indiana Utilities Corporation	$ 159.78	$ 209.20	$ 258.61
10	Indiana Natural Gas Corporation	$ 159.31	$ 208.96	$ 258.61
11	Aurora Municipal Gas	$ 154.60	$ 205.25	$ 255.91
12	Midwest Gas Corp.(Midwest) (4)	$ 157.02	$ 205.12	$ 253.22
13	Westfield Gas Corporation	$ 159.52	$ 204.97	$ 250.42
14	Community Natural Gas * (1)	$ 154.22	$ 199.96	$ 245.71
15	Boonville Natural Gas Corporation	$ 150.13	$ 196.18	$ 242.22
16	Northern Indiana Public Service Co.	$ 137.36	$ 181.31	$ 225.25
17	Indiana Gas Company	$ 137.59	$ 179.40	$ 221.21
18	Switzerland County Natural Gas	$ 131.94	$ 173.19	$ 214.43
19	Chandler Natural Gas Corporation	$ 130.19	$ 171.08	$ 211.95
20	Northern Ind Fuel & Light Co., Inc.	$ 130.83	$ 170.11	$ 209.40
21	Citizens Gas & Coke Utility	$ 129.12	$ 167.85	$ 206.58
22	Kokomo Gas and Fuel Company	$ 128.47	$ 165.80	$ 203.13
23	Southern Indiana Gas & Electric Co.	$ 118.63	$ 154.84	$ 191.05
24	Fountaintown Gas Company, Inc.	$ 107.11	$ 139.58	$ 172.05
25	Snow & Ogden Gas Company, Inc.	$ 75.20	$ 100.20	$ 125.20

* See “Areas Served” on page 28 for Service Area Descriptions

(1) See Note 1, page 28

(2) See Note 2, page 28

(3) See Note 3, page 28

(4) See Note 4, page 28

This Gas Bill Analysis should be construed as an informative guideline. It is a snapshot in time. Gas rates change frequently, in some cases monthly, due to gas cost adjustments. Using this analysis to draw conclusions about a particular utility’s performance would be difficult due to many factors such as utility size and resources, time since the last rate case, storage options, geographic location, base rates, customer density, and gas cost adjustment in effect at the time of bill calculation.

RESIDENTIAL GAS BILL ANALYSIS (2000-2004) BILLS CALCULATED BASED ON RATES IN EFFECT JANUARY FIRST OF EACH YEAR RANKED HIGHEST TO LOWEST BASED ON 5 YEAR AVERAGE							
		Consumption Level of 200 Therms					
Rank	**Utility Name**	**5 Year Average**	**2004 Bills**	**2003 Bills**	**2002 Bills**	**2001 Bills**	**2000 Bills**
1	Westfield Gas Corp.	178.89	204.97	167.15	213.05	185.36	123.92
2	Boonville Natural Gas Corp.	172.77	196.18	172.63	205.70	179.66	109.67
3	Ohio Valley Gas Corp. (ANR) * (2)	172.03	225.70	164.94	180.37	168.81	120.33
4	Lawrenceburg Gas Co. (Rate G-1) *	171.08	213.09	156.64	197.22	164.24	124.22
5	Indiana Utilities Corp.	166.75	209.20	150.89	189.05	158.65	125.97
6	Lawrenceburg Gas Co. (Rate G-2) *	163.42	211.84	138.18	179.40	166.26	121.43
7	Indiana Natural Gas Corp.	162.97	208.96	151.36	178.29	154.18	122.08
8	Northern Indiana Public Service Co.	162.78	181.31	179.35	127.81	210.91	114.53
9	South Eastern Indiana Gas Co.	162.76	211.19	147.09	172.41	162.41	120.71
10	Aurora Municipal Gas Utility	162.40	205.25	147.77	184.96	156.95	117.06
11	Community Gas Corp. (Rate 1)* (1)	161.35	199.96	145.77	205.47	141.26	114.31
12	Switzerland County Natural Gas Co.	158.07	173.19	144.31	199.79	150.85	122.19
13	Ohio Valley Gas Corp. (TXG) *	157.77	220.18	144.48	168.15	157.27	98.75
14	Ohio Valley Gas Inc. *	155.44	223.52	137.72	172.89	148.97	94.09
15	Midwest Gas Corp. (Peoples) (3)	153.38	216.02	121.94	162.00	154.34	112.61
16	Indiana Gas Co.	152.76	179.40	161.32	133.22	175.40	114.46
17	Chandler Natural Gas Corp.	152.15	171.08	148.57	179.36	153.39	108.35
18	Community Gas Corp. (Rate 2)* (1)	150.57	199.96	123.33	173.82	150.16	105.56
19	Midwest Gas Corp.(Midwest) (3)	149.88	205.12	125.25	155.57	151.34	112.11
20	Northern Indiana Fuel and Light Co.	148.18	170.11	141.90	192.85	130.65	105.41
21	Fountaintown Gas Co.	144.62	139.58	144.86	180.32	139.60	118.76
22	Citizens Gas and Coke Utility	141.29	167.85	146.66	125.92	157.44	108.58
23	Kokomo Gas and Fuel Co.	132.14	165.80	131.60	154.01	113.27	96.00
24	Southern Ind. Gas & Electric Co.	127.56	154.84	146.42	108.80	134.82	92.94
25	Snow and Ogden Gas Co.	100.20	100.20	100.20	100.20	100.20	100.20

* See “Areas Served” on page 28 for Service Area Descriptions

(1) See Note 1, page 28

(2) See Note 2, page 28

(3) See Note 4, page 28

This Gas Bill Analysis should be construed as an informative guideline. It is a snapshot in time. Gas rates change frequently, in some cases monthly, due to gas cost adjustments. Using this analysis to draw conclusions about a particular utility’s performance would be difficult due to many factors such as utility size and resources, time since the last rate case, storage options, geographic location, base rates, customer density, and gas cost adjustment in effect at the time of bill calculation.

AREAS SERVED

<u>**Community Natural Gas**</u>

Rate 1

Serving: Dale, Mariah Hill, Santa Claus and Gentryville

Rate 2

Serving: Owensville, Cynthiana, Holland, Worthington, Carlisle and Spencer

<u>**Lawrenceburg Gas**</u>

Rate G-1, <u>Lawrenceburg Division</u>

Serving: Greendale, Lawrenceburg, Rising Sun and West Harrison

Rate G-2, <u>Brookville Division</u>

Serving: Brookville

<u>**Ohio Valley Gas Corp.**</u>

ANR Consolidated Area

(**Formerly ANR**; ANR Pipeline System)

Serving: Ferdinand, Pennville, Portland, St. Anthony, St. Marks and St. Meinrad

(**Formerly PE**; Panhandle Eastern Pipeline System)

Serving: Deerfield, Fountain City, Lynn, Ridgeville, Saratoga, Union City and Winchester.

TXG; Texas Gas Transmission System

Serving: Cannelton, Connersville, Everton, Guilford, Lawrenceville, New Alsace, Sunman, Tell City, Troy and Yorkville

<u>**Ohio Valley Gas, Inc.**</u>

Serving: Dugger, Farmersburg, Hymera, Riley, Shelburn, Sullivan and Winslow

<u>**Notes:**</u>

1. Community Natural Gas Rate 1 and 2 were consolidated pursuant to Commission order in Cause No. 42452, dated 11/20/03.
2. Ohio Valley Gas "ANR" and "PE" service areas were consolidated pursuant to Commission order in Cause No. 40049, dated 11/09/95. The consolidated area was named "ANR" to distinguish it from the "TXG" service area.
3. Valley Rural Utility Co. began natural gas service in July 2003 and is not included in the 5 and 10 year averages because there is not enough data at this point in time.
4. Peoples Gas & Power Co., Inc. merged with Midwest Natural Gas Corp. in Cause No. 42246, dated 2/5/03. The customer groups of the merged company are split into Midwest Division and Peoples Division.

APPENDIX E

History of U.S. Gas Market Deregulation

1938 The National Gas Act (NGA)

The NGA created the Federal Power Commission (FPC) to regulate natural gas pipelines (but not wellhead prices). Rapid growth in the 1940s and 1950s outpaced pipeline expansion, which led to price volatility and supply shortages in some areas. Producers requested price caps, but the FPC said it did not believe it had the authority to set them.

1954 The Supreme Court determined the NGA should encompass the regulation of both pipelines and wellhead prices. This was known as the **Phillip's Decision**, and the court held that the primary aim of the NGA was the "protection of consumers against exploitation at the hands of natural gas companies."

This created an industry structure that consisted of price-regulated gas producers, who sold to price-regulated pipelines, who in turn sold gas on to local distribution companies (LDCs). LDCs then sold the gas onto end users (LDCs were regulated by state or local government agencies).

Price volatility was reduced by the Phillip's Decision, but it eventually caused supply shortages - it encouraged consumers to buy relatively cheap fuel but did not provide any incentive to producers to replace reserves.

1978 Natural Gas Policy Act

The Federal Energy Regulatory Commission (FERC) was created out of the old FPC and directed to reform natural gas pricing.

Essentially this was a reversal of the Phillip's decision as it allowed the deregulation of wellhead gas prices.

Production increased dramatically in response to pent-up demand which led to a gas surplus in the 1980s. However, a competitive market failed to develop, mainly due to the role pipelines played in the market. Since pipelines charged consumers enough to cover the cost of what they had to pay producers, there was no incentive for them to select the most competitively priced gas produced.

1985 FERC Order 436

This required pipelines to provide open access to transportation services allowing consumers to negotiate prices directly with producers and contract separately with the pipelines for transportation.

1987 FERC Order 500

Order 500 implemented shared contract costs on take-or-pay (TOP) contracts. Take-or-pay contracts leave the buyer responsible for some portion of the cost even if the product is not provided.

The combination of Orders 436 and 500 allowed producers to balance supplies of gas across production regions - if volume was lacking in one area, but plentiful in another, the producer could arrange to transport the surplus to where it was needed. The transportation system became a mechanism one party owned, but could be accessed by other parties on an equal basis - hence the concept of open-access. Differences between contract gas shipments and actual consumption left pipelines to make up the difference (balancing) and FERC made balancing a competitive service.

The establishment of gas market firms was also a feature of the 1980s, a direct result of deregulation. These firms, often with no ties to any one gas company, provided an intermediary service between a gas buyer and all other industry segments.

1989 Natural Gas Wellhead Decontrol Act

This act completed the process of deregulating wellhead prices. It required the removal of all price controls on wellhead sales as of Jan. 1, 1993, allowing natural gas prices to be freely set in the market.

1991 Mega-Notice of Proposed Rulemaking (Mega-NOPR)

FERC requested comments from consumers and industry about new ways of structuring gas transportation.

1992 The Restructuring Rule (FERC Order 636)

Order 636 resulted in major restructuring of interstate pipeline operations. The most notable provisions of Order 636 were the separation of sales from transportation services (unbundling), so that customers could select supply and transportation services from any competitor in any quantity and combination, making TOP contracts a thing of the past.

Order 636 successfully impacted the market resulting in increased exploration, pipeline construction, falling prices and increasing profits.

2000 FERC Order 637

Order 637 provided further refinement of the remaining pipeline regulations to address inefficiencies in the capacity release market.

Deregulation in the gas industry has seen the development of commodity products that parallel the evolution of physical natural gas markets. Consumers can negotiate the best terms for supply and transportation to their site and simultaneously negotiate better terms in other markets as a price hedge. The natural gas commodity market is now the most active commodity market on the NYMEX.

The deregulation of the US gas industry has been extremely successful - production has increased, proved reserves have decreased, gas usage is increasing and consumer prices have dropped significantly.

[Editor’s note: Circumstances have changed significantly since Platt’s wrote this conclusion.]

Source: http://www.platts.com/usgashistory.shtml