

Natural Gas Purchase Incentive Regulation and Benchmarking

A White Paper Prepared for the Indiana Utility
Regulatory Commission (IURC)

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July 2005

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Natural Gas Purchase Incentive Regulation and Benchmarking

1. Introduction

The purposes of this white paper are: (a) to summarize the general picture of the near term gas supply-demand, potential shortage and high prices; (b) to emphasize the importance of gas purchase risk management due to the large volatility of gas prices; and (c) to summarize the benchmarks and incentive mechanisms some other states have used and lessons that may be learned as the State of Indiana has been facing similar situations.

Natural gas prices in the United States have been high for the past few years and will probably remain high in the near future due to many reasons. Figure 1 shows that gas spot prices have been above \$5/MMBtu for most of the time during the past year and prices have been very volatile since 2000, a dramatic contrast to the situations before the early 1970s (see Figure 2).

According to analyses, the high prices are largely due to demand-supply imbalance – i.e., supply cannot meet demand growth, reduced imports from Canada, and increasing exports to Mexico. Natural gas demand growth during the past few years was largely caused by the mushrooming of gas-fueled peak power plants and partly by national economic recovery. Figure 3 shows that gas power plant additions are the dominant new resource for power generation. The power plant database compiled by the State Utility Forecasting Group (SUFG) shows that almost 280,000 MW of gas-fired power capacity are either in service or under development since 1999 (http://engineering.purdue.edu/IE/Research/PEMRG/SUFG/MAFS/index_html).

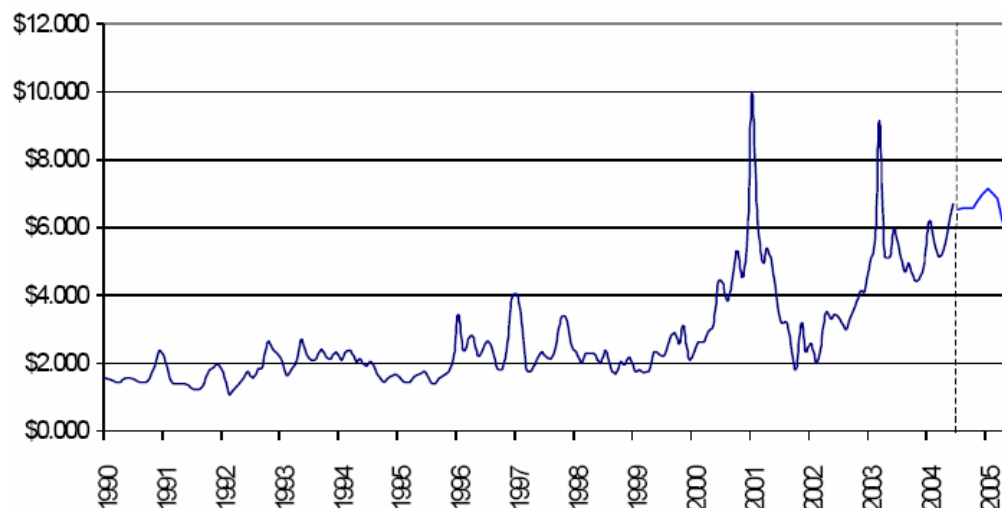


Figure 1. NYMEX natural gas spot prices

Source: NYMEX

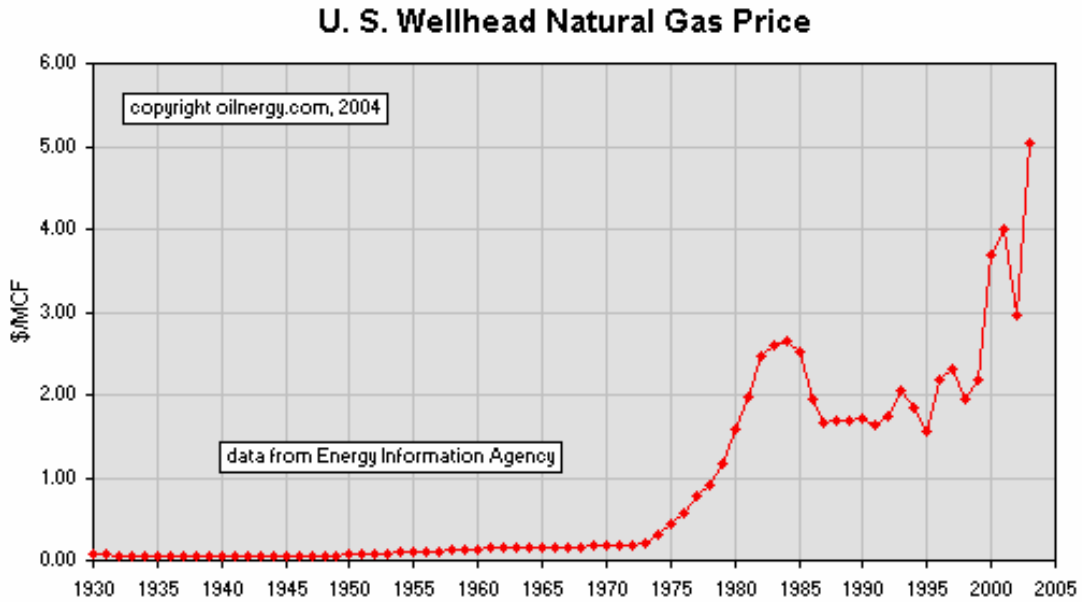


Figure 2. Historical wellhead gas prices

Source: oilnergy.com

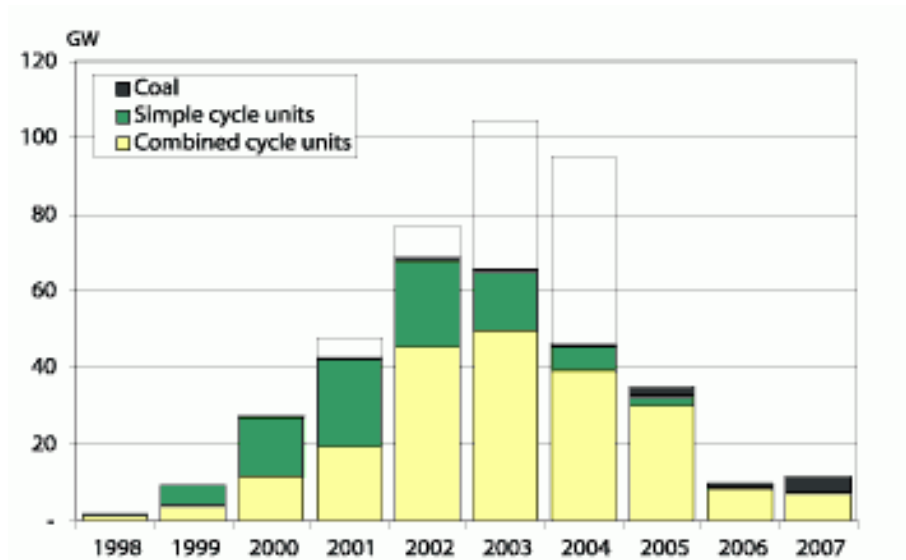


Figure 3. Gas-fired power plant additions

Source: Electric Power Research Institute (EPRI), "Gas-Fired Building Boom Will Hasten Fossil Plant Retirement," <http://www.epri.com/journal/details.asp?doctype=features&id=542>

Another factor that may have contributed to the high prices is market manipulation. For example, some companies have been fined by the Federal Energy Regulatory Commission (FERC) for submitting false information to raise gas prices. FERC also conducted an

investigation into possible pipeline capacity withholding between Texas and Southern California in 2000-2001, and a settlement was reached in 2003 with El Paso Energy (Appendix A). According to *Natural Gas Intelligence* on 7/19/2004 and other sources, Enron will pay \$35 million to the Commodity Futures Trading Commission (CFTC) to settle charges that it, along with one of its natural gas traders, Hunter Shively, engaged in a scheme to manipulate the Henry Hub natural gas spot and futures markets on July 19, 2001. (Shively also agreed to pay \$300,000 to settle charges against him.) Some have argued that high oil prices may be another factor contributing to the high natural gas prices. Nonetheless, this white paper does not intend to quantify the causes of the high gas prices. Rather, its purpose is to analyze incentive regulation for local distribution companies (LDCs) to better manage their gas purchases at the lowest possible cost, reduce price volatilities, and mitigate risks.

For the past few years, the volatility of gas prices has been very significant and will likely remain so due to various factors such as seasonal variations, extreme weather conditions, international market variations, and so forth. Gas purchase risks are significant in terms of both prices and liquidity. Therefore, appropriate incentives may allow LDCs to better manage risks of their purchases at low cost for the benefit of the gas ratepayers.

This white paper will summarize the basics of natural gas supply, price movement, actions other states have been taking, and a general picture of various benchmarks and incentive mechanisms being experimented with by some states. These mechanisms and others can be explored as Indiana regulators consider the general direction of possibly new incentive regulation. As stated by the Indiana Utility Regulatory Commission (available at <http://www.in.gov/iurc/>), "The Commission's mission is to assure that utilities and others use adequate planning and resources for the provision of safe and reliable utility services at reasonable cost." Good benchmarks and incentives would bring results that comply with the goal of achieving "reasonable cost" for consumers in Indiana as the commission has been considering the renewal of incentive based gas purchase regulation.

SUFG is also conducting a gas purchase benchmarking project using a mathematical model coupled with simulations. The project has been underway and preliminary results are expected to be available later this year.

Throughout this white paper, regulatory commission docket cases and text are quoted from time to time. Quotation marks are used for direct quotes without any change. Italicized text is used for quotes with minor editing.

2. The General Picture of Gas Demand-Supply for the Next Few Years

The gas supply in the U.S. markets has been stagnant for the last few years while demand is increasing due to the causes mentioned above. Gas supply may even be declining compared to 2001 if liquefied natural gas (LNG) imports do not catch up with the demand growth, as pointed out by Strategic Energy & Economic Research Inc. [1] and Cambridge Energy Research Associates (see Figure 4, where it presents a general picture of the trend from which a possible gas shortage can be seen for the next five years or so according to the forecast by Cambridge

Energy Research Associates in 2003; notice that BCF stands for billion cubic feet in Figure 4 and the rest of this paper).

Several factors may contribute to potential natural gas shortages. First, Canadian exports to the U.S. have been declined due to growth in domestic demand in Canada and depleting gas reserves, as well as reduced gas production over the past few years. Second, local production in the U.S. has not increased much while exports to Mexico have increased. Many gas fields in the U.S. have been producing less gas due to depletion. Third, LNG imports from international gas markets are still very limited, primarily due to a lack of terminals to handle the imports. This section will provide a brief summary of the above-mentioned aspects.

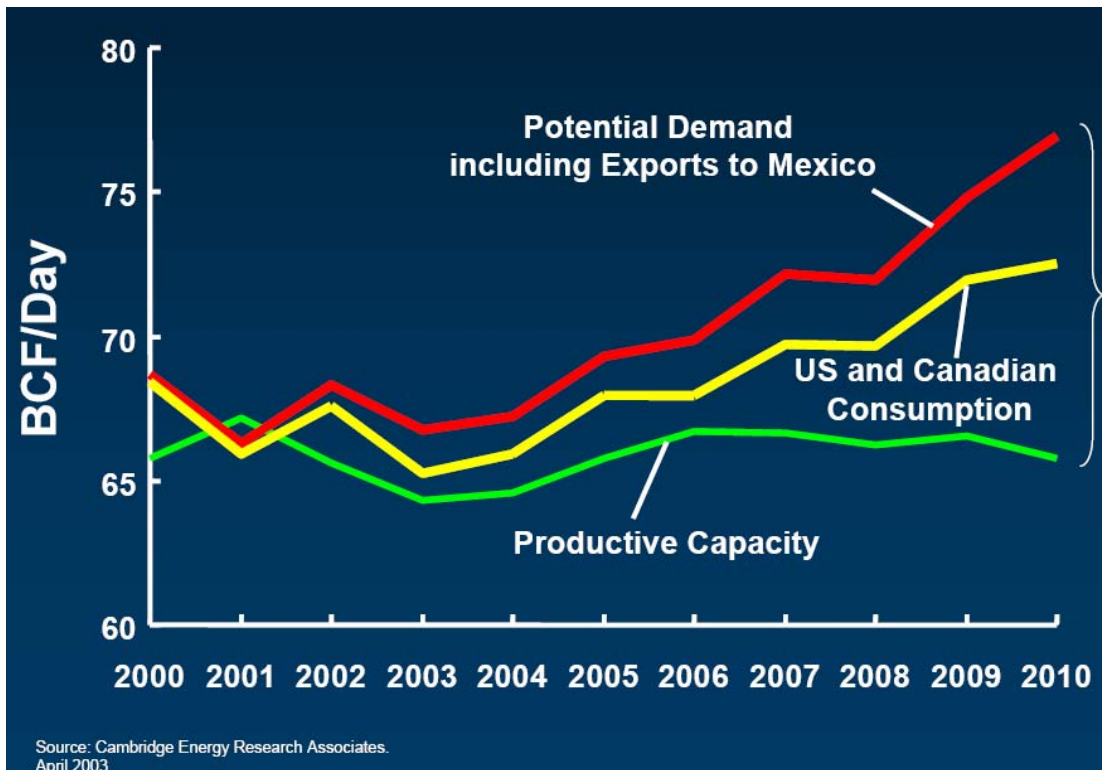


Figure 4. North American gas demand forecast
 Source: Cambridge Energy Research Associates, April 2003

2.1 Canadian Gas Imports to the U.S.

Canadian gas production has been declining since late 2002 after reaching its peak in 2001–2002, according to many sources. The major reason for this decline is the depletion of its gas wells. Table 1 illustrates the Canadian gas production in trillion cubic feet (tcf) and depletion over the last 11 years. The table displays the difficulty Canada has had in increasing its natural gas production.

Year	Production (tcf) (EIA)	Well depletion (Daily Oil Bulletin)	Comments
1993	4.52	3,239	
1994	4.91	5,370	
1995	5.27	3,618	
1996	5.60	3,726	
1997	5.71	4,857	
1998	5.76	4,585	
1999	5.98	6,309	
2000	6.26	8,934	
2001	6.47	11,177	
2002	6.50	9,073	
2003	6.30	12,500	estimate

Table 1. Canadian gas production and wells depleted

Source: Canadian Gas Association

Canadian natural gas production would have experienced a more significant decline without the massive Ladyfern field in British Columbia. From its start in 1999, the field reached its peak production of 665 million cubic feet a day (mmcf/d) in March 2002, according to the British Columbia Energy Ministry and the U.S. Energy Information Administration (EIA) [2]. This accounted for 10% of Canada's total natural gas production. With its production dropping rapidly [2], it is estimated that Ladyfern may be totally depleted by the end of 2004. Ladyfern's gas depletion may only speed up the fall of Canadian gas production in the future.

The best hope in the Canadian gas reserves is Canada's massive deposits of coal bed methane (CBM). While early estimates of total recoverable CBM reserves are rather substantial, it is unlikely that the Canadian CBM development will make up for its declining production from conventional natural gas wells. (See Natural Resources Canada's website at: http://www2.nrcan.gc.ca/es/ener2000/online/html/chap3b_e.cfm.) CBM currently constitutes no more than 1% of total Canadian natural gas production and it may be a few years before the Canadian CBM has a significant impact on gas markets. A boom in Canadian gas exports to the U.S. in the near future is not anticipated.

2.2 Stagnant Gas Production in the U.S.

U.S. gas production, which has been stagnant with a decline in 2002 as compared to 2001 and again in the second quarter of 2004, can be felt through the decline of production in Texas, Louisiana, and Oklahoma because these states produced almost half of the gas in the U.S. previously. According to the *Oil & Gas Journal* on August 10, 2004, U.S. natural gas production fell by 3.8% in the second quarter of 2004 despite the persistently very high gas prices (the number is obtained from Raymond James & Associates Inc., based on a survey of 47 publicly traded U.S. oil and natural gas exploration and production companies). This is notable

from the near-term perspective because gas prices have been high for about two years, enough time to stimulate new production.

2.2.1 Texas

Texas, the largest state producer of natural gas with approximately 30% of total U.S. production, represents an important benchmark for U.S. gas production as a whole. The production numbers from the Texas Railroad Commission provide a clear insight into the production decline in the past (2003 and before). While Texas natural gas production has been flat at 5.6 tcf per year with a peak production of 5.81 tcf in 1997, the number of natural gas wells needed to keep production flat has risen by nearly 30%. This is significant because it may not be sustainable in the long run for the state to maintain the 30% number unless a significant number of new gas wells are developed. Moreover, the first year average decline rate of new wells has been over 50% for the past few years, compared to only 10% in the early 1970s, another troublesome sign for Texas gas production, as indicated in Figure 5 below.

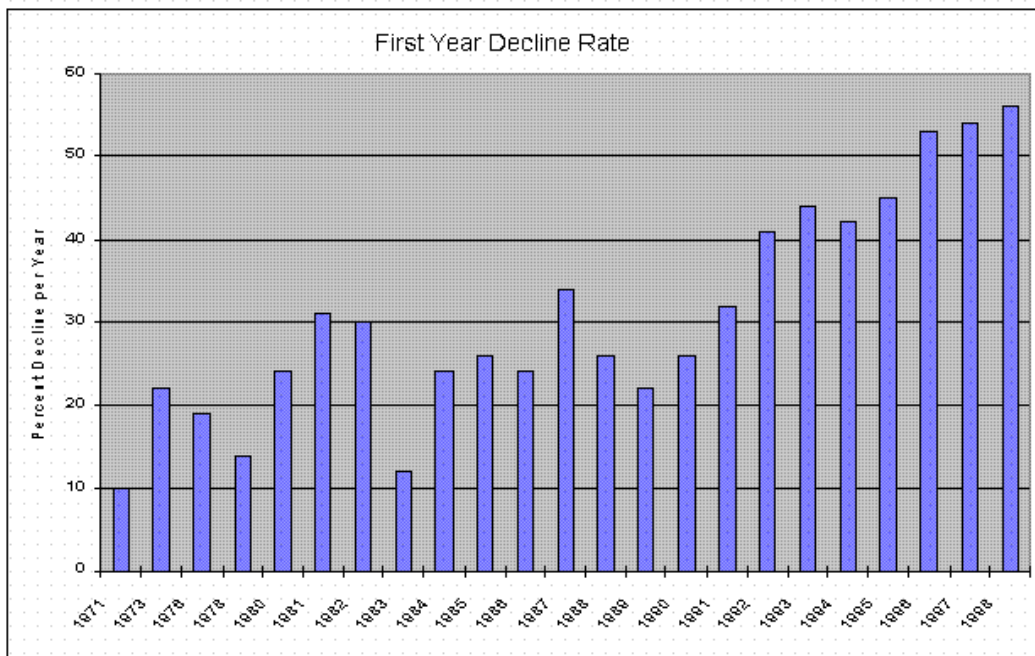


Figure 5. Average first year decline rate of gas wells in Texas

Source: *Texas Production data show rapid gas depletion*, Oil & Gas Journal, June 21, 1999

2.2.2 Louisiana

Natural gas production in Louisiana had also been declining as of 2003. Louisiana gas production ranks second in the nation when federal waters production figures are included. While production remained relatively flat for most of the past decade with a peak production of 1,566,916 mmcf in 1999 (EIA data), natural gas production in the state experienced its first substantial decline in 2002. According to EIA, the number of wells completed in the last five years of the past decade was significantly higher than the number completed before, indicating

an accelerated development of new wells. Considering the record gas prices for all of 2003, the state's recent production problems become even more severe. If producers in the state and in the nation as well are unable to significantly step up production activities at these high prices, this would be a clear indication of production efficiency decline.

2.2.3 Oklahoma

Oklahoma was once well known for its oil industry, and natural gas has also played a significant role in Oklahoma's history. Gas production peaked in 1992 in the state with a total annual production of 2.0 tcf and now is about 1.6 tcf per year. The decline has been steady for the past decade.

2.2.4 The Lower 48 States as a Whole

Although a list of gas wells depleted in the U.S. is unavailable, the decline of gas production in the Gulf Coast is partly due to accelerated production decline of new wells as illustrated in Figure 6. EIA data from natural gas wells in the federal offshore Gulf of Mexico show that wells drilled in recent years are declining more quickly than wells drilled in the 1970s (see Figure 6). EIA estimates that the average production from natural gas wells that began producing in 1996 was 69% lower than it had been at its peak. "In contrast, the decline in production over the 23 months after wells drilled in 1972 had reached their peak production was only 39 percent" [3].

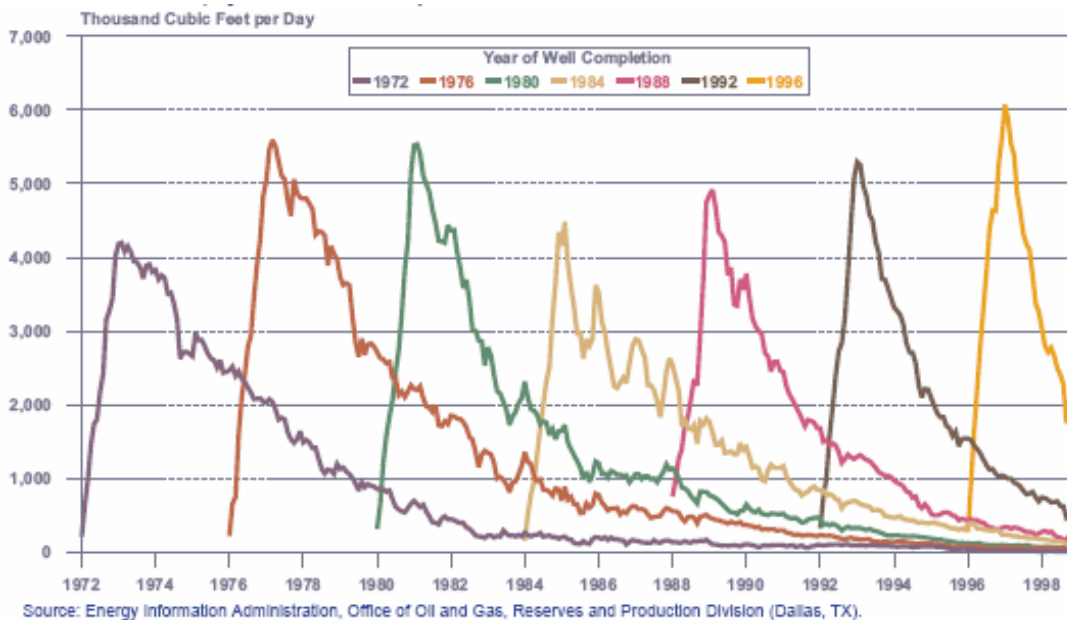


Figure 6. Declining gas production in the Gulf Coast (by year of well completion).

Source: Energy Information Administration

According to EIA, gas depletion in the continental U.S. has been accelerating recently. The depletion trend is summarized by EIA and available at EIA's webpage. Figure 6 shows the general trend of depletion.

On the other hand, gas production in the Rockies has increased recently. This increase has played a significant role in curbing the overall decline in gas production in the U.S. Figure 7 illustrates the changes of production and import of natural gas in the U.S. with 2001 as the reference. As can be seen, LNG import is considered to be a critical element in the U.S. gas demand-supply equation, which will be discussed in the next section. In Figure 7, the 2002 data is actual, and the rest are projections, all measured as incremental changes against the year 2001.

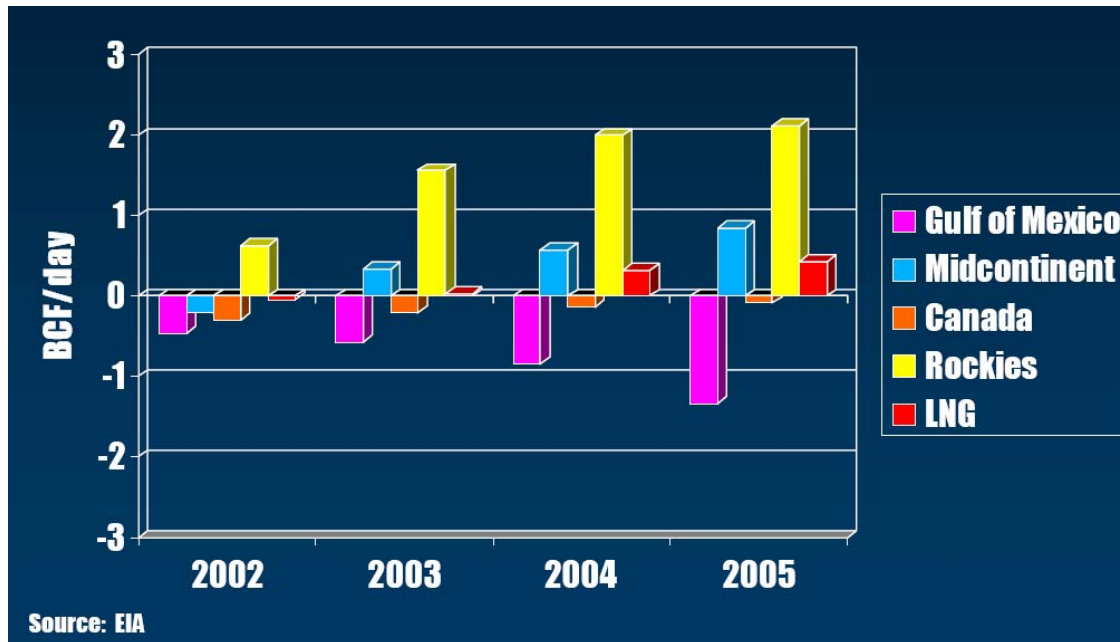


Figure 7. Change in gas supply – history and short-term forecast (relative to 2001)

Source: Energy Information Administration

2.2.5 Alaska

Alaska may provide the needed natural gas for the nation in the future. The U.S. legislature recently approved an initiative to open federal lands in the state for exploration. This may result in considerable amount of natural gas that can be transmitted to the mainland U.S. However, unless the pipeline connecting Alaska to the mainland U.S. is built, the gas transmission may be limited. Recently, some sources estimate that it may take another 10 years for the natural gas from Alaska to play a significant market role in North America (see [7] and [8]).

2.3 LNG Imports

Currently, LNG accounts for about 1% of the U.S. gas supply, while it is about 48% in Japan. The U.S. has been exporting LNG to Japan for some years from Alaska (the total export to Japan was 66 BCF in 2002). According to some estimates (EIA; Institute for Energy, Law & Enterprise; etc.), the LNG cost is around \$3.5/mmBTU. Considering the high natural gas prices in North America, it is natural to envision a large market for LNG imports into the U.S. There

were 35 LNG-processing terminals proposed as of January 2004, and the proposed LNG terminals had reached 50 in the U.S. and Canada, plus five in Mexico as of March 2005 according to EIA, which is a significant move for the North American natural gas market [8].

However, the short-term perspective of LNG import is limited due to insufficient transportation and port facilities. There are currently about 150 LNG container ships worldwide with limited transshipment capability (this number includes tankers built from 1965 to 2003, calculated by The LNG Center, data available at <http://gmaiso.free.fr/lng/index.php3>). It would take a few years to add the needed fleet size. Also, there are not enough LNG gasification terminals in the U.S. to handle a surge in LNG import. Terminal constructions are subject to government regulation and would require long lead times (see Figure 8 for existing and proposed LNG terminals).

The 50 plus proposed LNG terminals are a big jump as compared to the existing five. However, not all these are likely to be built. Construction of liquefied natural gas plants in California and elsewhere has caused heated debate and emotional reactions. Many local communities do not want them nearby. Federal and state regulators have also been fighting over many issues. For example, FERC Commissioner Joseph Kelliher called on California regulators to drop their challenge to FERC's claim of "exclusive jurisdiction" over the siting and construction of a planned LNG terminal for the Port of Long Beach, saying the state could turn out to be the biggest loser if it continues its effort (*Natural Gas Intelligence*, 6/29/04). The divisive nature of the subject prompted some firms to pull out of the deals (*Powermarketers*, 3/26/04).

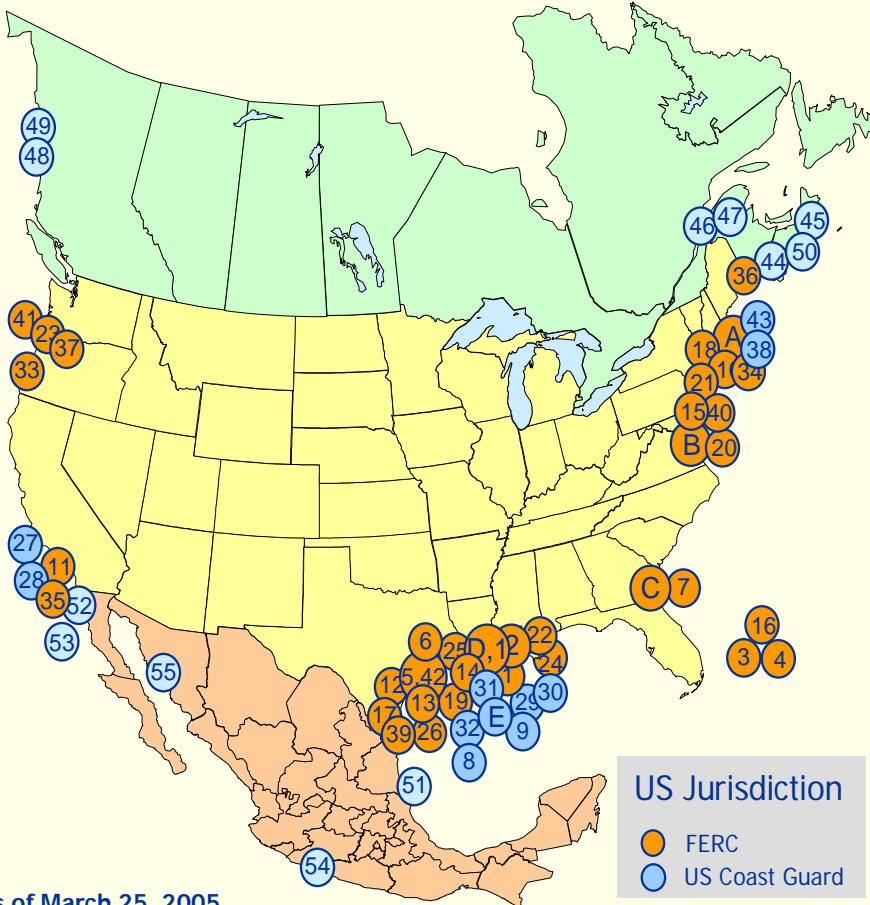
The longer-term perspective of LNG imports depends largely on two factors: potential returns and safety considerations. The latter has dominated the news lately. In the face of terror threats, safety will remain as an important issue in the decision on LNG terminals, and local community objections will remain strong. Calpine Corp backed out of building a plant in Eureka, California, because the local community adamantly opposed it [4]. The same debate over safety has been occurring in Fall River, Massachusetts, and elsewhere. Safety is now coupled with security concerns particularly over terror attacks.

In short, there are uncertainties and risks with LNG imports and the future road cannot be expected to be very smooth. In addition, the LNG prices likely will be volatile due to international competition once the U.S. dramatically increases its import, which will affect the overall gas prices in the U.S. markets for the next few years.

This general picture illustrates the possible large uncertainties and risks in gas supply and prices, which dictates the need for Indiana LDCs to manage risks over a longer time frame. This also calls for a more vigorous discussion on incentive regulation among various parties in the state.

FERC

Existing, Proposed and Potential North American LNG Terminals



Office of Energy Projects

Figure 8. (A) Existing and proposed LNG terminals in North America

CONSTRUCTED

- A. Everett, MA : 1.035 Bcfd (Tractebel - DOMAC)
- B. Cove Point, MD : 1.0 Bcfd (Dominion - Cove Point LNG)
- C. Elba Island, GA : 0.68 Bcfd (El Paso - Southern LNG)
- D. Lake Charles, LA : 1.0 Bcfd (Southern Union - Trunkline LNG)
- E. Gulf of Mexico: 0.5 Bcfd, (Gulf Gateway Energy Bridge - Excelerate Energy)

APPROVED BY FERC

- 1. Lake Charles, LA: 1.1 Bcfd (Southern Union - Trunkline LNG)
- 2. Hackberry, LA : 1.5 Bcfd, (Sempra Energy)
- 3. Bahamas : 0.84 Bcfd, (AES Ocean Express)*
- 4. Bahamas : 0.83 Bcfd, (Calypso Tractebel)*
- 5. Freeport, TX : 1.5 Bcfd, (Cheniere/Freeport LNG Dev.)
- 6. Sabine, LA : 2.6 Bcfd (Cheniere LNG)
- 7. Elba Island, GA: 0.54 Bcfd (El Paso - Southern LNG)

APPROVED BY MARAD/COAST GUARD

- 8. Port Pelican: 1.6 Bcfd, (Chevron Texaco)
- 9. Louisiana Offshore : 1.0 Bcfd (Gulf Landing - Shell)

PROPOSED TO FERC

- 10. Fall River, MA : 0.8 Bcfd, (Weaver's Cove Energy/Hess LNG)
- 11. Long Beach, CA : 0.7 Bcfd, (Mitsubishi/ConocoPhillips - Sound Energy Solutions)
- 12. Corpus Christi, TX : 2.6 Bcfd, (Cheniere LNG)
- 13. Corpus Christi, TX : 1.0 Bcfd (Vista Del Sol - ExxonMobil)
- 14. Sabine, TX : 1.0 Bcfd (Golden Pass - ExxonMobil)
- 15. Logan Township, NJ : 1.2 Bcfd (Crown Landing LNG - BP)
- 16. Bahamas : 0.5 Bcfd, (Seafarer - El Paso/FPL)
- 17. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy - Occidental Energy Ventures)
- 18. Providence, RI : 0.5 Bcfd (Keyspan & BG LNG)
- 19. Port Arthur, TX: 1.5 Bcfd (Sempra)
- 20. Cove Point, MD : 0.8 Bcfd (Dominion)
- 21. LI Sound, NY: 1.0 Bcfd (Broadwater Energy - TransCanada/Shell)
- 22. Pascagoula, MS: 1.0 Bcfd (Gulf LNG Energy LLC)
- 23. Bradwood, OR: 1.0 Bcfd (Northern Star LNG - Northern Star Natural Gas LLC)
- 24. Pascagoula, MS: 1.3 Bcfd (Casotte Landing - ChevronTexaco)
- 25. Cameron, LA: 3.3 Bcfd (Creole Trail LNG - Cheniere LNG)
- 26. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG - Gulf Coast LNG Partners)

PROPOSED TO MARAD/COAST GUARD

- 27. California Offshore: 1.5 Bcfd (Cabrillo Port - BHP Billiton)
- 28. So. California Offshore : 0.5 Bcfd, (Crystal Energy)
- 29. Louisiana Offshore : 1.0 Bcfd (Main Pass McMoran Exp.)
- 30. Gulf of Mexico: 1.0 Bcfd (Compass Port - ConocoPhillips)
- 31. Gulf of Mexico: 2.8 Bcfd (Pearl Crossing - ExxonMobil)
- 32. Gulf of Mexico: 1.5 Bcfd (Beacon Port Clean Energy Terminal - ConocoPhillips)

POTENTIAL SITES IDENTIFIED BY PROJECT SPONSORS

- 33. Coos Bay, OR: 0.13 Bcfd, (Energy Projects Development)
- 34. Somerset, MA: 0.65 Bcfd (Somerset LNG)
- 35. California - Offshore: 0.75 Bcfd, (Chevron Texaco)
- 36. Pleasant Point, ME : 0.5 Bcfd/d (Quoddy Bay, LLC)
- 37. St. Helens, OR: 0.7 Bcfd (Port Westward LNG LLC)
- 38. Offshore Boston, MA: 0.8 Bcfd (Northeast Gateway - Excelerate Energy)
- 39. Galveston, TX: 1.2 Bcfd (Pelican Island - BP)
- 40. Philadelphia, PA: 0.6 Bcfd (Freedom Energy Center - PGW)
- 41. Astoria, OR: 1.0 Bcfd (Skipanon LNG - Calpine)
- 42. Freeport, TX: 1.5 Bcfd, (Cheniere/Freeport LNG Dev. - Expansion)
- 43. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG - Tractebel)

CANADIAN APPROVED AND POTENTIAL TERMINALS

- 44. St. John, NB : 1.0 Bcfd, (Canaport - Irving Oil)
- 45. Point Tupper, NS 1.0 Bcfd (Bear Head LNG - Anadarko)
- 46. Quebec City, QC : 0.5 Bcfd (Project Rabaska - Enbridge/Gaz Met/Gaz de France)
- 47. Rivière-du- Loup, QC: 0.5 Bcfd (Cacouna Energy - TransCanada/PetroCanada)
- 48. Kitimat, BC: 0.61 Bcfd (Galveston LNG)
- 49. Prince Rupert, BC: 0.30 Bcfd (WestPac Terminals)
- 50. Goldboro, NS 1.0 Bcfd (Keltic Petrochemicals)

MEXICAN APPROVED AND POTENTIAL TERMINALS

- 51. Altamira, Tamulipas : 0.7 Bcfd, (Shell/Total/Mitsui)**
- 52. Baja California, MX : 1.0 Bcfd, (Sempra & Shell)**
- 53. Baja California - Offshore : 1.4 Bcfd, (Chevron Texaco)
- 54. Lázaro Cárdenas, MX : 0.5 Bcfd (Tractebel/Repsol)
- 55. Puerto Libertad, MX: 1.3 Bcfd (Sonora Pacific LNG)

Figure 8. (B) Legend to LNG terminals in North America

Source: EIA/FERC (see reference [8])

3. Gas Purchase Incentive Regulation and Benchmarking – Experience of Some States in the U.S.

Due to persistently high gas prices for the last few years, many states have been searching for strategies to protect public interest. Dwindling production, tight supply, and high energy prices are likely to adversely affect economic recovery. High natural gas prices have caught regulators' attention and forced them to think of ways to enact incentive regulation so that LDCs would have a greater incentive to better manage risks, mitigate price shocks, and minimize their gas purchase cost. This section will introduce the actions that some states have taken on the issue and will also summarize the major methods some states have been using. Note that the actions and methods of some states will also include those taken prior to the high prices and price volatility that have occurred since 2002. The states listed are selected based on the following criteria: (1) they have experimented with PBR (performance-based regulation or rate-making) and benchmarks that have characteristics representative of other states; or (2) they have proposed but not yet experimented with PBR and benchmark(s) that have unique features; or (3) they oppose any PBR; or (4) they have encouraged LDCs to use sound financial instruments in gas purchase portfolios. Appendix C, compiled by the National Regulatory Research Institute, also lists actions taken last year even though these activities do not specifically center on incentives and benchmarks.

3.1 Arkansas

The Arkansas Public Service Commission (APSC), in its Order No. 3 of Docket No. 01-023-NO1 - *In the Matter of a Notice of Inquiry into Whether Arkansas Gas Utilities Should Integrate Gas Price Hedging, Fixed Price Options, and Other Alternative Mechanisms into Gas Procurement Plans*, adopted the Poky Principle for Gas Procurement Plans of Utilities ('Policy Principles'). APSC deems these policy principles as being consistent with Arkansas Code Ann. 523-15-103, the 'Least Cost Purchasing Statute.' The general principles are listed below.

3.1.1 Encourage LDCs to Develop Diversified Gas Purchase Portfolios

APSC expected that "each LDC take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio that should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments." The portfolio is designed to yield the optimum balance of reliability, reduced volatility and reasonable price. APSC requires that "each utility take into consideration various factors including, but not limited to, its particular circumstances, the demographics of its customers, the then-current market projections of both volatility and price, supply/demand estimates, and other relevant information available in the industry."

3.1.2 APSC Evaluates Portfolios Annually

In the same Order (No. 3), APSC requires that *each LDC submit its gas supply portfolio plan annually, along with its contracting and/or hedging objectives, to the General Staff for Staff's review and determination as to whether or not it appears to be consistent with these*

policy principles. According to the commission, the reasonableness and prudence of each utility's contracting and hedging decisions shall be judged by the market circumstances and pertinent information that was available to the utility at the time it made those decisions.

3.1.3 Costs Allowed to Recover for Risk Management

Costs associated with hedging and a particular financial risk management tool is allowed to flow through. That is, these costs can be recovered through the APSC's Purchased Gas Adjustment Clause (PGA).

3.1.4 Performance Measures

The primary performance measures are weighted average cost of gas (WACOG) and volatility of WACOG. Here, volatility generally means the variance of gas purchase costs or prices.

3.2 California

For the past decade or so, the California regulators have conducted several PBR experiments in both electricity and natural gas services. The state experimented with gas purchase incentive regulation or the Gas Cost Incentive Mechanism (GCIM), dating back to the 1990s. In 1993, San Diego Gas & Electric (SDG&E) entered an experimental agreement with the California Public Utilities Commission (CPUC) in which the amount of SDG&E's fuel cost to be recovered is a function of its actual costs and an average spot price for four major basins. This average spot price was said to be the 'benchmark' level which is the average price of 30-day firm spot supplies in the basins in which SoCalGas (the gas company of SDG&E) purchases natural gas (Docket D.93-06-092). Later, the state also extended the GCIM to two more LDCs in the state. Since the SDG&E case is typical in terms of benchmarking and incentives, it therefore will be explained in more detail.

Let y be the quantity of fuel (gas) purchase and the vertical axis the award/penalty; the functional relationship of the award and penalty is illustrated in Figure 9, in which BM is the benchmark point, and C is the point when penalty is initiated and the line segment CD represents the penalty function. That is, when actual cost is greater than C, the utility will absorb $x\%$ of the actual cost beyond the point BM. Likewise, A is the point when award is initiated and the line segment AB represents the award function. The total penalty is then $y(\text{Actual cost} - \text{BM})x/100$ and the award, $y(\text{BM} - \text{Actual cost})x/100$. The $x\%$ was originally 50% in the agreement. The mechanism permits full recovery of all costs within a tolerance band from A (98% of BM) to C (102% of BM), as indicated in Figure 9.

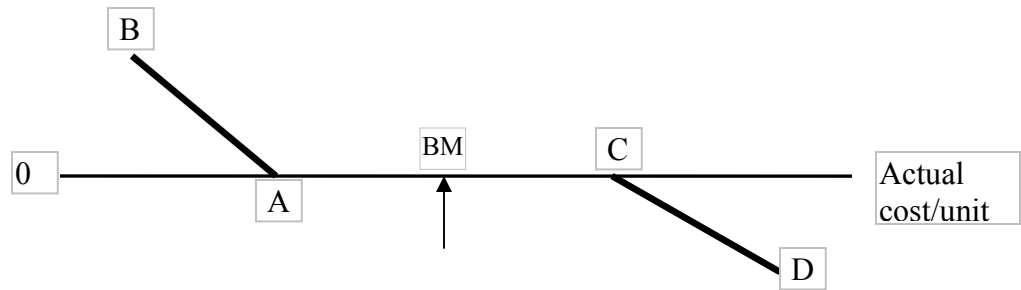


Figure 9. California award-penalty function

In 1998 the CPUC approved gas cost GCIM-related shareholder awards to SoCalGas (the gas company of Sempra Energy at this time) totaling \$13 million. On June 8, 2000, the CPUC approved an \$8 million award to the same company for the year ended March 31, 1999, and deferred its decision regarding extending the GCIM beyond March 31, 2000, until an evaluation could be performed by its staff. There has been no information whether SDG&E has been penalized for purchases with prices higher than the benchmark and it is possible that SDG&E has so far surpassed the benchmark ever since it was developed. On January 4, 2001, the CPUC's Energy Division issued its evaluation report recommending the continuation of the GCIM with modifications. (The following website indicates that the GCIM still holds in California: <http://www.edgar-online.com/bin/edgardoc/glimpseFrame.asp?doc=A-1032208-0000086521-04-000004&glm=1>.)

Theoretically, this experiment was limited because the benchmark was only limited to the average spot price for four major basins. Other options such as futures, forwards, and fixed contracts were not included.

3.3 Indiana

Indiana is one of the states that has experimented with gas purchase incentives. The Indiana Utility Regulatory Commission (IURC) issued an order (as a response to Cause No. 40342) in 1997 to establish a gas cost incentive mechanism (GCIM) for NIPSCO. The IURC also issued a rule-making for Indiana Gas Co. in 2002 (as a response to Cause No. 42233, which is a follow up of cause numbers 37394GC50S1 and 37399GC50S1 in 1996).

3.3.1 The GCIM for NIPSCO

The benchmarks for gas purchase (in terms of prices) are defined below:

Benchmark I: *For first of the month purchases, the Benchmark Price shall be an average of the first of the month (&FOM) spot market natural gas commodity prices published by Natural Gas Week as the 'Spot Prices on Interstate Pipeline Systems, Bid Week for (Applicable Month)' and in Gas Daily as the 'Monthly Contract Index.'*

Benchmark II: *For purchases not made on the first of the month, the index price shall be the average of the published Gas Daily ‘Daily Price Survey, Daily Midpoint’ and NGI’s Daily Gas Price Index ‘CASH MARKET PRICES’ natural gas commodity price applicable as of the date of the purchase. In the event that the pricing index is changed or eliminated by any of the above listed publications; Northern Indiana, the OUCC, and any such interested party whose gas supply purchases are subject to the GCIM (the ‘GCIM Parties’) agree to negotiate in good faith to restore pricing terms that are economically equivalent.*

The incentive mechanism is illustrated in Table 2 and Figure 10. Unlike the incentive mechanisms of some other states where award/penalty is usually 50-50, the IURC’s GCIM for NIPSCO had a greater penalty/award for NIPSCO when the gas cost deviated more from the benchmarks. This GCIM may be called an accelerated award/penalty, with the purpose of stimulating the LDC to seek greater incentives. The GCIM for NIPSCO is currently being reevaluated as part of settlement discussions related to an Alternative Regulatory Plan which includes Customer Choice.

Deviation from Benchmark	Incentive for NIPSCO	Consumers’ cost share	Comments
0-3% above benchmark	0	100%	100% cost pass through
3-4% above benchmark	30% penalty	70%	Consumers pay 70% of cost above BM, plus BM cost
4-6% above benchmark	50% penalty	50%	...
>6% above benchmark	70% penalty	50%	
0-2% below benchmark	30% award	70%	
2-4% below Benchmark	50% award	50%	
>4% below benchmark	70% award	30%	

Table 2. Incentive mechanism for NIPSCO

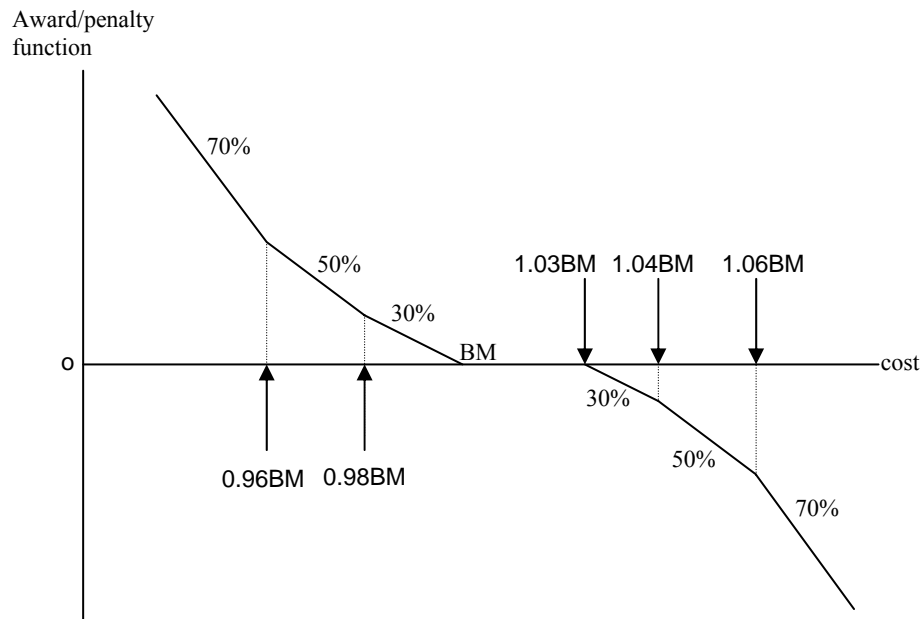


Figure 10. Indiana GCIM for NIPSCO

3.3.2 The Indiana Gas GCIM

The benchmarks for the Indiana Gas GCIM are similar to the ones with NIPSCO. Notice that this mechanism also covers the gas purchase by Citizen’s Gas. The following is a direct quote from the IURC order (as a response to Cause No. 42233).

(1) First of the month (‘FOM’) purchases. The applicable Benchmark Price(s) shall be the first of the month spot market natural gas commodity prices published in Platt’s inside FERC Gas Market Report (‘IFGMR’) as the ‘Prices of Spot Gas Delivered to Pipelines, [ApplicableMonth]’. In the event the IFGMR is discontinued or unpublished, then the substitute reference for applicable FOM prices shall be Platt’s Gas Daily price Guide – monthly contract index.

(2) Other purchases. For purchases not based upon first of the month applicable benchmark prices shall be based upon ‘Daily’ indices. The applicable Daily Benchmark Price(s) shall be the spot market natural gas commodity prices published in Platt’s Gas Daily ‘Daily Price Survey, Midpoint.’ If the Gas Daily Price Survey is discontinued or unpublished, then the substitute reference for applicable daily purchases shall be NGI’s Daily Gas Price Index ‘CASH MARKET PRICES.’

The incentive mechanism for Indiana Gas is that the cost savings will be shared equally by the consumers and the LDC. Furthermore, IURC requires that the LDC will receive 15% of the sales of excessive pipeline capacity reserved earlier and the consumers will receive 85%.

The GCIM will expire in March 31, 2007. Extension is possible depending on certain conditions.

3.4 Kansas

On July 1, 2000, the Kansas Corporation Commission (KCC) staff submitted its recommendations for the index-based performance benchmarks mechanisms in response to Docket 00-GIMG-425-GIG. The Docket was opened in November 1999 to consider an index pricing system for natural gas purchasing by LDCs. In the proposed index-based performance benchmarks, KCC staff recommended the Commission formally adopt a basic gas purchase standard.

The Commission can enforce that standard by implementing an index-based performance benchmarks mechanism that sets index-based benchmark prices. KCC staff recommended that different benchmark prices be applied to different contract types, depending on the contract's term and the pipeline to which the contracted supply is to be delivered. In short, all of KCC staff's recommended benchmark prices were term and pipeline specific. For instance, the benchmark price applied to daily contracts for gas delivered to Panhandle Eastern Pipeline Company would be identical to the PEPL (Oklahoma) index as published in Gas Daily. That same benchmark would apply to any Kansas jurisdictional LDC having purchased contracts of that type. KCC staff also recommended that only those contracts with daily and monthly terms be subject to a benchmark standard. To emphasize, mid-term and long-term contracts would not be subject to the benchmarks. Staff recommended that the benchmark for daily contracts be set equal to 100 percent of the relevant (i.e., pipeline specific) daily price index. Hence, KCC staff believed the daily price indices, as published, were reasonable benchmark prices. However, for monthly contracts, they recommend that the benchmark be set equal to 101 percent of the relevant (i.e., pipeline specific) monthly price indices. In other words, they believed there should be a premium adjustment equal to one (1) percent of the published monthly index. All of the benchmarks that would be applied under KCC staff's commendations are 'pure gas' benchmarks and thus, are not designed to recover the LDC's other variable costs, such as commodity transport costs.

In recommending different benchmarks for different contract types, it should be clear that they did not develop a single, composite benchmark formula that would be applied to all of the LDC's gas purchases. It is KCC staff's position that its recommended approach - which provides for a more disaggregated approach as opposed to a one-size-fits-all approach - simply provides a more accurate benchmark or benchmarks, as the case may be. They recommend that the Commission also implement, for at least one year, a sharing formula. They suggest that any difference between the LDC's actual purchase price of gas and the benchmark price be split 50/50 between shareholders and core customers.

Specifically, the benchmark for daily spot gas purchases is the spot price index and the benchmark for monthly purchase is 101% of the spot price index. Mid- and long-term gas purchases are allowed to completely pass through cost-wise. However, the commission staff also suggested another benchmark using the state average price: The LDC with the highest price was to pay \$10,000 to the LDC with the lowest price, which is a yardstick regulation (this is not implemented according to an email from Mr. John Cita at KCC to SUFG in October 2004).

SUFG staff confirmed via a telephone conversation with Mr. John Cita at KCC that KCC has implemented the recommended index-based performance benchmarks.

3.5 Kentucky

In an order issued on January 30, 2001, with a case number of 384, the Kentucky Public Service Commission (KPSC) required its five major LDCs to file reports addressing six issues, including: current gas procurement procedures; analysis of greater use of storage; analysis of performance-based rate-making mechanisms ('PBRs'); analysis of financial hedging practices; analysis of longer-term contracts; as well as including changes to current gas procurement or gas cost recovery processes. Based on the reports, the evidence of record, and being otherwise sufficiently advised, the Commission finds that (direct quote):

Recent and ongoing changes within the natural gas industry are sufficient reasons to call on outside expertise for evaluating the LDCs' gas planning and procurement strategies in greater depth. The consultant and Commission Staff will conduct a focused audit of the LDCs' gas planning and procurement strategies. Such an audit would assist the Commission in evaluating whether the LDCs' planning and procurement strategies are appropriate in today's more volatile wholesale markets with a primary focus on the development of a balanced portfolio that effectively addresses cost issues, price risk and reliability.

The LDCs should maintain their objective of procuring wholesale natural gas supplies at market clearing prices, within the context of maintaining a balanced natural gas supply portfolio that balances the objectives of obtaining low cost gas supplies, minimizing price volatility and maintaining reliability of supply.

The LDCs should consider storage development, performance-based ratemaking, limited hedging programs, and contract length and structure as strategies for attaining the objectives identified herein. Proposals developed by the LDCs should be considered by the Commission on a case-by-case basis.

LDCs should pursue a balanced natural gas procurement strategy that addresses the objectives of obtaining low cost gas supplies, minimizing price volatility and maintaining reliability of supply. The Commission believes that all of these objectives can be part of a coordinated gas procurement strategy that incorporates performance-based ratemaking with hedging and other price mitigation programs.

According to a conversation with the Commission, the above orders have been implemented in the gas purchase regulation. The Commission does not specify any gas planning and procurement strategies for its LDCs and force them to use them. Two of the LDCs are using hedging for their gas procurement, the others do not. A performance-based benchmarking mechanism is applied to the two LDCs based on the LDCs' willingness. The benchmark is proposed by the two LDCs and has to be approved by the Commission.

3.6 Massachusetts

The Massachusetts Telecommunications and Energy Department issued an order opening a Notice of Inquiry into the appropriateness of the use of risk-management techniques to mitigate natural gas price volatility (available at the commission's website; the order does not have a title or number; see <http://www.mass.gov/dte/index.htm>). The department requested comments regarding the implementation of a potential risk-management protocol for Massachusetts LDCs. Comments were filed by 14 different organizations about four relevant issues. Based on these comments, the department performed analyses and proposed its regulation policy of using risk-management techniques to mitigate natural gas price volatility. This policy does not include a benchmark. The four issues and associated decisions from the department are directly quoted below.

Whether Massachusetts gas utilities should be allowed, or required, to implement a risk-management program to mitigate price volatility for gas customers.

The Department will allow, but not require, Massachusetts LDCs to use financial risk-management instruments to mitigate commodity price volatility. The department will review and approve LDC risk-management proposals on a case-specific basis. Having concluded that they will not mandate the use of financial risk-management instruments to mitigate price volatility, the Department must address the effect that the use of such instruments may have on gas unbundling and customer choice in Massachusetts in the event that one of the LDCs proposes a hedging program.

How risk-management programs by LDCs would affect gas unbundling and customer choice in Massachusetts.

The Department concludes that financial risk-management programs would not adversely affect gas unbundling and customer choice in Massachusetts if they: (1) provide all customers with an opportunity to obtain more stable prices and costs are allocated only to those who participate in the program, and (2) ensure efficient competition among all suppliers involved in the merchant business.

Whether an incentive mechanism should be allowed in conjunction with a risk-management program.

The Department concludes that the use of incentive mechanisms in conjunction with LDCs' financial risk-management programs: (1) would not be consistent with the Department's goal of promoting market-based regulation and enhanced competition in that it would not 'serve as a vehicle to a more competitive environment'; and (2) could

negatively affect the development of retail competition and customer choice in Massachusetts. The Department, therefore, rejects the use of incentive mechanisms in conjunction with LDCs' risk-management programs.

What standard of review the Department should apply. And how costs for risk-management programs should be recovered.

The Department directs a company proposed risk-management plan to: (1) Allow customers to volunteer to participate in the plan; (2) maintain the objective of volatility mitigation and price stability rather than the objective of procuring prices below indices; (3) ensure fair competition in the gas supply market; (4) allocate all costs to program participants only; (5) demonstrate the effect that the plan would have on the reliability and transparency of commodity price; and (6) contain no incentive mechanisms.

3.7 Missouri

The Missouri Public Service Commission (MPSC) has taken steps to promote gas purchase risk mitigation strategies and has required Missouri LDCs to take proactive approaches in that direction. The MPSC states that natural gas utilities should consider the use of a broad range of pricing structures, mechanisms, and instruments, including gas storage, futures contracts, fixed price contracts, call options, swaps, and other tools for cost-effective management of price and/or usage volatility. According to Mr. Warren Wood, manager of MPSC's gas department via a phone conversation with Dr. Zuwei Yu at SUFG, the commission desires to have a balanced portfolio for each LDC but falls short of prescribing percentages of the choices for the gas purchase (i.e., futures, options, etc.), and each LDC has the option to determine its own portfolio that it deems prudent.

Unlike Arkansas, MPSC does not prescribe a benchmark for measuring the gas purchase performance. However, it does have a benchmark if the LDC purchases gas from its affiliate(s). The commission states that "In transactions involving the purchase of information, assets, goods or services by the regulated gas corporation from an affiliated entity, the regulated gas corporation will use a commission-approved cost allocation mechanism (CAM) which sets forth cost allocation, market valuation and internal cost methods. This CAM can use benchmarking practices that can constitute compliance with the market value requirements of this section if approved by the commission." This statement can be found on the MPSC website at <http://urc.state.us.mo/>

The following is the section on gas purchase rule-making by the commission, which can be found in "Rules of Department of Economic Development – Chapter 40: Gas Utilities and Gas Safety Standards." It is interesting to note that MPSC recognizes that a portfolio may produce prices higher than spot prices at times, and that this is a result of mitigating upward volatility that may have more serious consequences if not mitigated.

CSR 240-40.018 Natural Gas Price Volatility Mitigation (by MPSC)

PURPOSE: This rule represents a statement of commission policy that natural gas local distribution companies should undertake diversified natural gas purchasing

activities as part of a prudent effort to mitigate upward natural gas price volatility and secure adequate natural gas supplies for their customers.

(1) Natural Gas Supply Planning Efforts to Ensure Price Stability.

(A) As part of a prudent planning effort to secure adequate natural gas supplies for their customers, natural gas utilities should structure their portfolios of contracts with various supply and pricing provisions in an effort to mitigate upward natural gas price spikes, and provide a level of stability of delivered natural gas prices.

(B) In making this planning effort, natural gas utilities should consider the use of a broad array of pricing structures, mechanisms, and instruments, including, but not limited to, those items described in (2)(A) through (2)(H), to balance market price risks, benefits, and price stability. Each of these mechanisms may be desirable in certain circumstances, but each has unique risks and costs that require evaluation by the natural gas utility in each circumstance. Financial gains or losses associated with price volatility mitigation efforts are flowed through the Purchased Gas Adjustment (PGA) mechanism, subject to the applicable provisions of the natural gas utility's tariff and applicable prudence review procedures.

(C) Part of a natural gas utility's balanced portfolio may be higher than spot market price at times, and this is recognized as a possible result of prudent efforts to dampen upward volatility.

(2) Pricing Structures, Mechanisms and Instruments:

(A) Natural Gas Storage;

(B) Fixed Price Contracts;

(C) Call Options;

(D) Collars;

(E) Outsourcing/Agency Agreements;

(F) Futures Contracts;

(G) Financial Swaps and Options from Over the Counter Markets; and

(H) Other tools utilized in the market for cost-effective management of price and/or usage volatility.

Appendix B provides definitions for the above mentioned instruments. For more detailed explanations of these financial instruments, various text books and manuals are available [5, 6].

3.8 Texas

Texas initiated discussions on natural gas purchase PBR in the late 1990s and continued the discussions until 2001 under the Texas Railroad Commission (TRC). The Texas Public Utility Commission (TPUC) also conducted a series of workshops on the subject. Several suggestions have been made since then, but there has been no indication that they were put in practice. Nonetheless, an examination of the suggestions is of interest.

Originally the primary goal for the discussions was for the state to set up a “*prudent standard in gas purchases, which does not prescribe a specific portfolio, but requires utilities to show their actions were just and reasonable.*” It was not intended to prescribe an ideal gas supply portfolio. However, in the process of discussions, several organizations proposed some performance measures (or benchmarks) and one of them is the weighted average purchase cost (WAPC). In this method, WAPC is defined over a specific time period (e.g., a year) as

$$WAPC = \frac{\text{Total gas purchase cost by all LDCs}}{\text{Total volume of gas purchased}} \quad (1)$$

If the LDC’s cost is above this WAPC, it will not be allowed to pass through the cost but a fraction of the cost up to 50%. If, however, the LDC’s cost is below this WAPC, it will receive an incentive bonus of the same percentage. Apparently, this method would force the LDCs to compete against each other for better performance in gas purchases if they are not allowed to collude (i.e., to have the same or similar purchase cost).

A second suggestion was to use the national weighted average instead of statewide weighted average. Considering that Texas is a major gas producer in the nation (30%), the state average gas purchase cost should be lower than the national average. Therefore, the second suggestion apparently favored the LDCs. Some consumer groups argued that poor benchmarking would not be beneficial to consumers and worst of all, would reward companies that did poor or mediocre jobs (a utility might be simply awarded for being less bad).

There is a need for safeguarding against potential collusion among the LDCs if the WAPC is used as a benchmark. The collusion can be in a form of joint gas purchase by the LDCs so that they can have the same price. Regulators can enforce a policy forbidding such behavior.

There is no indication that any PBR has been enforced in Texas. The gas regulator is the Railroad Commission in the state, and the TPUC did not have the authority to enforce a PBR for the gas purchases even though it participated in the PBR discussion. From the webpage provided by the Texas Railroad Commission (<http://www.rrc.state.tx.us/>), the state measures their residential gas cost relative to the national average cost of the same category using percentages and calls it the benchmark.

3.9 Washington

The Washington Utilities and Transportation Commission (WUTC) experimented with an incentive regulation with Puget Sound Energy (PSE), a LDC in the State of Washington. The docket number is UG-980832 (rule No. 27). The experiment lasted three years and was terminated at expiration after October 2001. According to Mr. Mert Lott, a staffer from WUTC, via a phone conversation with Dr. Zuwei Yu at SUFG, the reason for the termination was that PSE was risk averse when the benchmark was set by WUTC. The commission alleged that PSE did not conduct innovative gas purchases but stuck to the benchmark. Nonetheless, it is still worthwhile to examine the details of the Gas Purchase Adjustment (GPA) clauses set by WUTC.

The purpose of the commission's GPA was to give PSE an incentive so that PSE would beat the commission's benchmark to earn the preset bonus that is percentage of the cost saving. The benchmark has several categories listed below.

3.9.1 Fixed Gas Service Benchmark: *a predetermined monthly dollar amount representing the company's costs of maintaining firm pipeline and storage capacity.*

3.9.2 Variable Service Benchmark: *a product of the predetermined Benchmark Variable Unit Cost (BVUC) multiplied by the actual sales volume. The BVUC is a pre-determined unit rate representing the average cost to the LDC for using pipeline and storage capacity.*

3.9.3 Gas Supply Benchmark: *the sum of the Benchmark Purchase Cost (BPC) and the Benchmark Withdrawal Cost (BWC). The BPC is the weighted average of 'the first of the month' gas prices of four gas sources that Puget Sound Energy often purchases gas, where 'the first of the month' prices are taken from FERC postings. The four sources are: Sumas, AECO-C of the Northwest Pipeline, the Rocky Maintains, and El Paso Natural Gas – San Juan Basin areas. This number may be adjusted for a few percent as deemed necessary as a pre-determined index adder. The BWC is a product of the withdrawal volume and the unit withdrawal cost that is set by the following formula: the sum for each of the previous months of the products of the fuel adjusted weighted averaged index price for the month divided by the pre-determined fuel adjustment factor from the company's most recent PGA filing.*

3.9.4 Actual Fixed Service Cost: *the actual monthly pipeline and storage fixed charges reduced by the after-tax revenues derived from capacity release transactions as recorded in the company's books for the month.*

In short, the benchmark covers all of the possible costs the LDC (i.e., Puget Sound) could have in gas purchases. Therefore, the effect of the benchmark is a complete cost "pass through" if the LDC sticks to the benchmark. There is no penalty "risk" if the LDC sticks to the benchmark. This might be the reason why the LDC did not engage in creative or innovative purchase strategies to save the consumers' costs while earning the designed incentive (bonus).

3.10 Other States

States other than those mentioned previously have also taken certain steps in tackling high natural gas prices. The approaches to the problems by these states are for the most part similar and thus are not discussed further. There are many reports on the issue that can be found on the Internet.

There was also a meeting of some state regulators as a response to high natural gas prices last year. A brief summary of state activities in response to high gas prices is provided in Appendix C of this paper. More activities by the states are expected this year.

4. The General Picture of Performance-Based Regulation and Benchmarking, and Emerging Issues

Though many states have considered the use of performance-based regulation on gas purchases by LDCs, their opinions on PBR vary. As a result, only a limited number of states have adopted specific PBR mechanisms and benchmarks for natural gas purchases by LDCs.

Table 3 summarizes the various strategies used by some states, together with the associated incentives. Notice that all the PBR incentive programs are voluntary, and often were initiated by the LDCs themselves.

	BS: Spot gas price indices	BS: weighted average of spot prices	BS: relative performance of state LDCs	Detail review of portfolio w/o BS	Encourage use of diversified portfolios	Incentive: award – penalty %
AR	n/a	yes	n/a	yes	yes	n/a
CA	n/a	yes	n/a	yes	yes	50-50
IN	yes	n/a	n/a	yes	yes	30-70 and 50-50
KS	n/a	yes	suggested	yes	yes	50-50
KY	n/a	n/a	n/a	yes	yes	n/a
MA	n/a	n/a	n/a	n/a	voluntary	n/a
MO	n/a	n/a	n/a	yes	yes	n/a
TX	n/a	n/a	proposed but not in use	yes	yes	proposed 10-50
WA	n/a	yes but given up	n/a	yes	yes	n/a

Table 3. Gas purchase strategies of some states
(BS = benchmark strategy, n/a = not available)

4.1 The Benchmarking Formulas

A few PBR benchmarking formulas have been proposed or used by the states mentioned previously. The most commonly used are the weighted average cost (calculated from the spot prices of several locations where the LDC purchases natural gas), some public indices such as the NGI indices used by Indiana, and the weighted average cost across LDCs in a state. Some states use various benchmarks for different types of contracts such as forwards and spots (e.g., Kansas), while some other states use a one-for-all benchmark (e.g., California, Washington, and the Texas proposal).

Mathematical and simulation portfolio models can be used for producing benchmarks according to theory. These models have not been seen in practice, perhaps mainly due to the difficulty of implementation.

4.2 Characteristics of the Gas Purchase Incentive Programs

A summary of the gas purchase PBR of the states shows that relatively simple mechanisms have been used. The mechanisms include various approaches ranging from non-mandatory use of portfolio and/or risk management tools to detailed portfolio selection criteria. Some states evaluate or audit the gas purchase contracts of their LDCs in detail if the states do not prescribe portfolio selection criteria (e.g., Missouri and Massachusetts). As for the PBR programs, they are voluntary and negotiated between state regulators and LDCs.

The award is often 50% of the gas purchase savings referenced in the benchmark for some states. The penalty is also 50% of the extra cost of gas purchase relative to the benchmark. One exception is Indiana where an accelerated award/penalty function is used for NIPSCO, as mentioned earlier.

For portfolio selection, a few states such as Missouri encourage LDCs to consider a large spectrum of financial instruments in gas purchasing. This strategy is sound from a financial point of view because most low cost and/or low variance candidates are taken into consideration at a cost of complexity. On the other hand, some other states only consider a few spot natural gas markets in the interest of simplicity.

Multiple purchase sources are often required or prescribed by state commissions in gas purchase portfolio selections. This may lead to less risky portfolios than portfolios with just one source or two. According to portfolio theory, one should consider all choices and variables in portfolio selection provided that one can handle the computation burden. Of course, one may exclude those variables that are apparently inferior to others in terms of either costs of variances or both through a prescreening procedure.

4.3 Emerging Issues

People are still debating the merits of benchmarking and PBR. In essence, a good benchmark and PBR would encourage LDCs to better manage gas purchase risks at the lowest possible costs. However, benchmarks and PBR mechanisms, if they are not properly set, would have the same effect as a “complete cost pass through” or even worse.

LDCs may not take advantage of the PBR incentives. One example is Puget Sound Energy that stuck to the benchmark set by the Washington state commission. The major reason is that the LDC was so “risk averse” that it did not conduct innovative gas purchasing activities as claimed by the state commission.

Another issue is education on portfolio and risk management. Small LDCs do not have the manpower to configure complex portfolios in their fuel purchases. The State of Indiana may develop gas purchase portfolio criteria for the LDCs to formulate sound portfolios that take into consideration all opportunities. SUFG has been conducting research in this area, has developed several versions of gas purchase portfolios, and could lead the effort in discussion and training.

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Appendix A

Sample Cases of Natural Gas Price Manipulations

According to FERC in its report (*The Final Report on Price Manipulation in Western Markets (Western Markets Report)*) issued March 2003 in Docket No. PA02-2-000), participants in the western gas markets attempted to manipulate published price indices through epidemic false reporting. Further, the problem was not limited to the western markets but to all of the U.S. and Canada. According to a report released on April 15, 2004, by the Industrial Energy Consumers of America (IECA), gas price manipulations have cost consumers \$1.3 billion in gas costs (IECA Report “46 Month Natural Gas Crisis Costs Consumers Over \$130 Billion”). The following cases represent indictments, arrests, fines, settlements and investigations resulting from gas price manipulations. The italicized text is taken directly from the sources listed with limited editing.

1. *US attorneys indicted a former **Dynegy** trader on Monday for giving false price data to a natural gas reporting publication, a move that should further erode confidence in the industry’s price indexes. Commodity Futures Trading Commission (CFTC) gained in its settlement with Dynegy that resulted in a \$5 million fine against them, CFTC said. The settlement found that Dynegy and its joint venture with NRG Energy -- West Coast Power -- gave false prices to the reporting publications from January 2000 through June 2002. (Source: American Public Gas association (APGA) news, August 24, 2004).*
2. *In December 2002, an **El Paso** gas trader was arrested on similar charges and has pleaded not guilty. Prosecutors have accused Geiger of being part of a two-year conspiracy to manipulate prices. (Source: APGA news, August 24, 2004).*

Lieff Cabraser Heimann & Bernstein, LLP represents California residential and business consumers of natural gas in a class action lawsuit, entitled Natural Gas Antitrust Cases, filed against El Paso Natural Gas. The complaint alleges that during California’s energy crisis in 2000-2001, El Paso rigged an auction for natural gas pipeline transmission capacity into California so that its energy trading subsidiary would acquire the capacity, and then used the capacity to drive up prices on the spot market for California consumers and businesses in violation of antitrust and unfair competition laws. In December 2003, Superior Court Judge J. Richard Haden granted final approval to an almost \$1.5 billion class action settlement. The settlement class, with certain exceptions, includes all California residential and business consumers that purchased natural gas or electricity between September 1, 1996 and March 20, 2003. (Source: http://www.lieffcabraser.net/cal_wholesale_power.htm).

3. ***Duke Energy** was fined 28 million by the federal regulator for Duke Energy Trading ‘knowingly reported trades that did not occur and reported certain trades at false prices and/or volumes in an attempt to skew the indexes to benefit...’. (Source: www.dukeemployees.com, September 19, 2003).*

4. **Coral Energy Resources L.P.** has agreed to pay \$30 million to settle regulatory allegations of attempted market manipulation and false trade reporting, joining more than two dozen companies that have ponied up a collective \$252 million.

The Commodity Futures Trading Commission late Wednesday issued an order that found traders at Houston-based Coral, an affiliate of Royal Dutch/Shell, reported false, misleading or knowingly inaccurate natural gas trading information to industry reporting publications from at least January 2000 through September 2002. The publications - Inside FERC Gas Market Report and Natural Gas Intelligence - use such information to calculate indexes of natural gas prices. The CFTC's order also said Coral tried to manipulate natural gas prices by reporting fake trades or altering price and volume information on certain trades. (Source: Kristen Hays, Associated Press, July 29, 2004).

5. **Sempra** revealed on Jan. 25, 2004 that federal investigators were probing the company regarding the gas price spike in 2003 that sent costs soaring more than 45% from Thanksgiving to mid-December. (Source: Freerepublic news, Jan. 2004). There was an earlier case against Sempra for its alleged collusion with El Paso for driving up gas prices on the West, according to John G. Edwards, Las Vegas Review Journal, Dec. 13, 2003.

6. **Aquila Inc.** agreed to pay \$26.5 million to settle charges that its energy-trading employees sought to manipulate natural-gas prices for more than three years, federal officials announced Wednesday. The Commodity Futures Trading Commission said that from at least January 1999 to June 2002, Aquila's energy-trading arm provided false information to companies that calculate natural-gas price indexes, which are widely used by gas utilities and others to set prices. The scheme was intended to enrich Aquila, the federal agency concluded. (Source: Steve Everly, The Kansas Star, Jan. 29, 2004).

7. The Commodity Futures Trading Commission said on Monday that a unit of Canada's **EnCana Corp.** agreed to pay a \$20 million fine to settle charges that it had attempted to manipulate the price of natural gas. The CFTC settlement order found that from at least June 2000 through at least Aug. 2001, EnCana's U.S.-based trading unit **WD Energy Services Inc.** reported false natural gas trading information, including price and volume data.

WD Energy and EnCana neither admitted nor denied the findings of the order, the CFTC said. The agency charged that one employee of WD Energy discussed false reporting with traders at two other energy companies. The WD Energy unit was a part of PanCanadian Energy, which bought Alberta Energy for C\$10.6 million (\$7.7 billion) in 2002 to form EnCana, now North America's biggest independent exploration and production company.

As the merger was being completed in the spring of 2002, EnCana shut the unit down, and took a C\$49-million charge to earnings.

The CFTC contended that WD Energy knowingly submitted false information to price reporting firms in an attempt to skew gas price indexes for its financial benefit and to manipulate the price of natural gas in interstate commerce. (Source: news from EnergyInforSource.com, July 28, 2003).

8. In 2004, FERC fined **Enron** \$35.2 million for its share in natural gas price manipulation. According to Forster Electric Online, more fines could be imposed to the company by FERC. (Sources: *Foster Electric Online news*, July 21, 2004 and *Natural Gas Intelligence*, 7/19/2004).
9. Williams Energy agreed to pay \$20 million to settle charges against its alleged gas price manipulation. The case was brought up by the CFTC in 2002 and closed in July 2003, according to PowerMarketers, July 29, 2003.

Appendix B

Glossary

In this appendix, a few terminologies are explained and their definitions are provided. For more detailed explanations, readers are referred to financial dictionaries. The definitions below are largely taken from the Derivative Dictionary™ compiled by THE WILLIAM MARGRABE GROUP, INC., and Dictionary of Financial Risk management, compiled by IFCI Risk Institute, with minor editing.

Collars:

A financial instrument that involves the simultaneous purchase of an interest rate cap and sale of an interest rate floor. This instrument has been applied to commodity markets such as natural gas, electricity etc.

Forwards:

A trade is **forward settled** if it settles on some date after spot. Forward transactions, called **forwards**, routinely have settlement dates up to one year after the trade date. Forwards also prescribe an obligation to the traders.

Futures:

A trade is **future settled** if it settles on some date after spot. Future transactions, called **future contracts** or **futures**, routinely have settlement dates up to several years after the trade date. Futures prescribe an obligation to the traders.

Option:

An **option** is a contract, or a provision of a contract, that gives one party (the **option holder**) the right, but not the obligation, to perform a specified transaction with another party (the **option issuer** or **option writer**). An owner of natural gas might sell another party an option to purchase the gas any time during the next year at a specified price. However, the option purchaser can exercise the option right or not depending on the market condition at expiration. Hence, a **call** option provides the holder the right to purchase an underlier at a specified price.

Swaps:

A natural gas **swap** is a financial contract wherein two parties exchange cash equal to the difference between an agreed fixed price and a floating price.

In addition to the futures contract that serves as the pricing benchmark for North American natural gas, the New York Exchange also provides a financially settled Henry Hub natural gas swap futures contract. The addition of this flexible contract to the Exchange's portfolio of cleared risk management instruments gives market participants additional

opportunities and choices for managing their price risk. The final settlement of the swap futures contract is based on the final settlement price of the NYMEX Division Henry Hub natural gas futures contract for the corresponding contract month on the last trading day for that month. All positions will be aggregated and margined according to the value at risk as calculated by the SPAN® system. Cross margining of offsetting positions across markets can result in reduced margin obligations.

A natural gas **basis swap** is a financial contract wherein two parties exchange cash equal to the difference between an agreed Fixed Basis and a Floating Basis:

- Location basis is the difference in prices between two locations;
- Commonly calculated as the difference between the NYMEX contract settle price at expiration and the Inside FERC first of the month published index.

Appendix C

State Activities in Response to the Current Gas Supply Situation

This appendix is taken directly from NRRI with very limited editing. The document was published in July 2003.

The NRRI (National Regulatory Research Institute) has compiled information collected by the NARUC Staff Subcommittee on Public Information Officers in late June and early July. Thanks to all contributors (names in parentheses). Go to <http://www.nrri.ohiostate.edu/about/state-commission-links.php> for links to web sties of state commissions.

Alabama: The Public Service Commission had not officially acted in response to the gas supply situation, but something may be planned later. The state's largest regulated natural gas utility, Alagasco, has issued a news release that warns the public of the likelihood of high gas prices for next winter. The staff considers this a good example of a professional, responsible and proactive effort by the utility. (Contact: Clark Bruner)

Arizona: In 1998 the ACC adopted a 12-month rolling average purchased gas adjustment mechanism by setting the monthly PGA rate based on the average gas cost for the previous 12 months; the mechanism also bands the PGA rate so that it cannot change more than \$0.10 per therm within a 12-month period, absent special commission approval. In 1998 the ACC recognized price stability as one of the goals of the gas-procurement process and directed the LDCs to procure a portion of their gas supplies through longer-term fixed price supply options; in April of this year, the ACC issued a notice of inquiry addressing pipeline and storage facility issues in the state. The commission July 10 issued a press release on a FERC decision requiring Arizona contracts for wholesale natural gas capacity on the El Paso pipeline to be converted from 'full requirements' contracts to contracts with limited rights on Sept. 1. ACC says the FERC decision is 'likely to usher in a period of price volatility for wholesale natural gas users.' (Contact: Heather Murphy)

Arkansas: The Arkansas Public Service Commission had adopted natural gas procurement plan rules. Those rules are available on the commission's web page. Each gas utility is required to develop a procurement plan that ensures reliability, safety, reasonable prices and mitigation of price volatility. Part of that process is consideration by a gas utility of physical and financial hedging.

The commission conducted a conference in early June where the current natural gas supply and price outlook were discussed. The commission invited members of the media, general assembly and the public to attend. Those presentations are available on the commission's web page. The commission's rural and community liaison is meeting with community leaders to discuss the prospects for high gas prices this winter. The commission is considering other means to educate customers regarding the expected gas prices for the upcoming heating season. (Contact: John Bethel)

Delaware: The Delaware commissioners were to be updated by staff concerning the gas-supply situation at the public meeting scheduled for July 22. (Contact: Bruce Burcat)

Georgia: The Georgia Public Service Commission issued two consumer advisories this year to alert the public to higher than normal natural gas prices. The commission also expected to run radio spots across the state beginning July 14 for two weeks advising consumers of volatile natural gas prices and the need to compare gas marketer prices and possibly lock in on fixed-term price contracts. The commission plans to run additional spots in September along with print ads in major markets across the state. The commission has communicated this information to state legislators. (Contact: Bill Edge)

Idaho: The commission issued a press release June 30 that announced the commission's approval of a 33 percent increase for Intermountain Gas, the state's largest gas distributor. Avista Gas, which serves the northern part of the state, is expected to file their annual purchased gas cost adjustment by August, and a slight increase is expected. The commission is working on a press release and web page information explaining the natural gas crisis and what customers can do to mitigate its impact. (Contact: Gene Fadness)

Indiana: Indiana held a gas forum on July 10 to discuss utility supply plans for the upcoming winter. (Contact: Elizabeth Herriman)

Iowa: Iowa issued a white paper last month, and it is available on the board's website at www.state.ia.us/iub. The board wants gas utilities to take the lead in communicating to their customers. The Board also wants to raise public officials' awareness of what could happen if all the pieces fall into the wrong places ('the perfect storm' scenario). After issuing the white paper to the governor's energy advisory committee, the commission sent a media advisory to selected major Iowa media outlets making them aware of the paper. Iowa's largest newspaper, the *Des Moines Register*, used the paper (almost verbatim text from many sections of the white paper) as the basis for an editorial on the subject in which the *Register* also pushed Senator Grassley (Chairman of the Senate Finance Committee) to get more federal dollars for heating assistance to low-income households. The board's chairperson also contacted the NARUC Natural Gas and Consumer Affairs Committees' chairs about a joint resolution to be proposed at the summer meeting in Denver to raise awareness and to call for additional federal funding for low-income households. (Contact: Chuck Seel)

Kentucky: The Kentucky PSC was undertaking a major public education effort to inform consumers of the prospect of high heating costs this winter and of the steps they can take to deal with them -- budget billing, weatherization, assistance programs and so forth. The education effort is being undertaken in cooperation with other state agencies and the major LDCs in the state. Key elements of the effort include:

- § Press releases
- § Media events with the LDCs and local officials to highlight weatherization programs
- § Background briefings for news media
- § Speaking appearances

§ Radio public-service announcements

The commission would be communicating with legislators to keep them informed on the gas supply situation. The commission has drafted a communication plan, which can be obtained from commission personnel. Incidentally, in the winter of 2000-2001 the PSC conducted five field hearings on gas prices and did not find them to be a terribly effective way of informing the public. This year, the commission instead did information-gathering through meetings with the LDCs (which also covered the results and implementation of a focused management audit of the LDCs, which looked at, among other things, their gas purchasing/hedging practices) and will be doing a media-based information effort. Receptivity to the message appears to be greatly enhanced as a result of the attention given to Alan Greenspan's comments last month. (Contact: Andrew Melnykovich)

Michigan: The Michigan PSC had started a proceeding on the current gas supply situation. Information on the proceeding can be found on the Commission's website at www.michigan.gov/mp (Contact: Gary Kitts)

Mississippi: The Mississippi commission planned to hold a technical conference in late August to review and discuss the current gas-supply situation. (Contact: Bob Marsh)

Missouri: The Missouri Public Service Commission had issued several press releases alerting consumers of the possibility of high natural gas prices. The Public Information and Education Department has also issued several fact sheets. For examples see their website www.psc.mo.gov.

Other things the commission had done:

§ Generic Docket (GO-2002-452) to implement a number of recommendations of Natural Gas Commodity Price Task Force regarding timing and consistency of purchased gas adjustment filings

§ Current rulemaking (GX-2002-478) regarding tools to consider in developing gas purchasing portfolio to mitigate upward price volatility

§ Current rulemaking regarding cold-weather rule reporting.

§ Commissioner updates in agenda on status of natural gas market and storage.

§ Inquiry letters and tracking of LDCs' storage, fixed price contracts, hedging efforts, under collection levels and number of disconnected customers

In addition, they were considering holding a number of local public meetings in August to alert consumers to the potential of higher natural gas prices this winter. (Contact: Kevin Kelly)

Montana: The Commission would be holding a gas roundtable in September on the issue of high gas prices. (Contact: Marla Larson)

New York: In previous years, the PSC issued brochures, press releases or consumer alerts notifying consumers of high gas prices and identifying conservation actions that can reduce gas bills. In 1999, the PSC accelerated customer refunds to help mitigate high gas prices. Department staff conducts a pre-winter review of each gas utility's preparedness for the winter with regard to

adequacy of gas supply and capacity, and each company's plans to address gas price volatility through financial or physical hedges.

Department staff conducted monthly meetings of the Natural Gas Reliability Advisory Group, which consists of representatives of the gas utilities, marketers, pipeline owners, generators and consumer representatives, where the implications of high gas prices on reliability is addressed.

The commission had undertaken steps to improve communications between the oil and gas industries, particularly on the issue of periods when large volume, interruptible gas customers were required to switch to alternate fuels. The goal is to facilitate discussions and a better understanding between the interrelated industries. With respect to consumer activities, their 'Conserve a Little, Save a Lot' program for the coming season would include a consumer alert on New York's natural gas outlook; radio, print and outdoor advertising, direct mail, as well as presentations to community groups and exhibits at consumer events. (Contact: David Flanagan)

Oregon: The commission had scheduled a natural gas forum July 16 to discuss the outlook for winter natural gas prices. Coverage of the forum in the state's major daily is expected. The commission prepared press releases for distribution before and after the forum. The commission expects to undertake an outreach effort concerning energy-savings ideas in late September, when the commission finalizes its annual reset of gas rates for the state's three natural gas distribution companies. Two general rate cases involving gas utilities are underway. (Contact: Bob Valdez)

Rhode Island: The state of Rhode Island had only one natural gas distribution company - Providence Gas (a subsidiary of Southern Union Co.). About two years ago the commission approved a procurement plan/hedging program for Providence Gas that has stabilized gas prices as well as can be expected. The commission had, however, had to grant gas recovery increases because of higher natural gas prices. (Contact: Terry Mercer)

South Carolina: The state of South Carolina has two natural gas distribution companies -- SCE&G and Piedmont Natural Gas. Both of these companies have currently in place commission-approved hedging programs that have provided some price stability over the past two years, as people have seen volatile prices at the wellhead. Over the last two years their Commission has granted recovery of gas-cost increases to reflect the higher price of natural gas that has not been offset by the hedging programs. (Contact: Gary Walsh)

Virginia: The Virginia SCC each October issued an advisory regarding the potential for high gas costs during the winter heating season (<http://www.state.va.us/scc/news/higas.htm>). They also developed an explanation of gas costs (<http://www.state.va.us/scc/division/pue/gascosts.htm>). They strongly encourage natural gas utilities to advise customers through bill inserts and web site information. The gas utilities (following the shocking prices during the 2000/2001 winter) are doing a better job of keeping state lawmakers and their staffs advised of the cyclical nature of wholesale gas prices. They have been keeping state lawmakers (and energy news reporters) abreast of the potential impact on electricity rates since more and more generation is relying on natural gas as a fuel used to generate electricity. That was confirmed July 1 with the fuel factor

filing of Dominion Virginia Power which experienced gas costs that were 39 percent higher than expected (<http://www.dom.com/news/elec2003/pr0701.jsp>).

The proposed 44 percent fuel factor increase, if approved, would result in an 8.7 percent increase in electricity costs to retail customers. (Contact: Ken Schrad)

Washington: Presentations by the state's four natural gas companies were made before the commission on June 27. The commission has posted on its website a media advisory and a summary of what the panelists had to say. They can be found at [natgaspresentation.doc](#). (Contact: Marilyn Meehan)