Special Issue: Upstream Natural Gas

Natural Gas & Electricity

June 2008

Volume 24
Number 11

THE MONTHLY JOURNAL FOR PRODUCERS, MARKETERS, PIPELINES, DISTRIBUTORS, AND END-USERS

Volatility Increasing Investment in Natural Gas Storage, but Also Risk

Lee Van Atta

Natural gas storage development is booming. Over the past few years, the number of projects under development has soared as capital poured into the sector. (See **Exhibit 1**.)

The scale of individual storage development projects has increased, and the activity in the sector has risen to a level that has attracted major investment funds and financial institutions.

With development costs running approximately $15 to $20 million a billion cubic feet of working gas (i.e., gas that can be economically withdrawn once injected), the current storage development pipeline amounts to around $12 billion in investment need. Thus storage is a massive opportunity for developers and investors. However, it also entails significant risk given the level of market exposure in the independent gas storage business, which is highly competitive and relies on market-based rates and relatively short-term negotiated contracts with customers.

Investors are constructing 110 billion cubic feet of working gas capacity, with another 600 billion cubic feet under development. If all the announced projects proceed, total U.S. working storage capacity would increase by over 20 percent over the next five years. This increase is significant but is even more transformational given the nature of the type of storage projects that are under development.

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Columns

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Printed on recycled paper.
Published online in Wiley InterScience (www.interscience.wiley.com).
DOI: 10.1002/gas.10082

Natural Gas & Electricity

Associate Publisher: Robert E. Willett **Executive Editor: Isabelle Cohen-DeAngelis**

Natural Gas & Electricity (ISSN 1545-7893, Online ISSN 1545-7907 at Wiley InterScience, www.interscience.wiley.com) is published monthly, 12 issues per year, by Wiley Subscription Services, Inc., a Wiley Company, 111 River Street, Hoboken, NJ 07030-5774. Copyright © 2008 Wiley Periodicals, Inc., a Wiley Company. All rights reserved.

Periodicals postage paid at Hoboken, NJ, and at additional mailing offices.

Subscription price (2008): One year print only: $1,289 in U.S., Canada, and Mexico; $1,361 outside North America. Electronic only: $1,289 worldwide. A combination price of $1,418 in U.S., Canada, and Mexico, $1,490 outside North America, includes the subscription in both electronic and print formats. All subscriptions containing a print element, shipped outside U.S., will be sent by air. Payment must be made in U.S. dollars drawn on a U.S. bank. Claims for undelivered copies will be accepted only after the following issue has been received. Please enclose a copy of the mailing label. Missing copies will be supplied when losses have been sustained in transit and where reserve stock permits. Please allow four weeks for processing a change of address. Address subscription inquires to Subscription Manager, Jossey-Bass, a Wiley Company, 989 Market Street, San Francisco, CA 94103-1741; Tel.: (888) 378-2537, (415) 433-1767 (International); E-mail: jbsubs@jbp.com.

Postmaster: Send address changes to Natural Gas & Electricity, Subscription Distribution US, c/o John Wiley & Sons, Inc., 111 River Street, Hoboken, NJ 07030-5774.

Reprints: Reprint sales and inquiries should be directed to Gale Krouser, Customer Service Department, c/o John Wiley & Sons, Inc., 111 River Street, Hoboken, NJ 07030-5774. Tel: (201) 748-8789. E-mail: gkrouser@wiley.com.

Other Correspondence: Address all other correspondence to: Natural Gas & Electricity, Isabelle Cohen-DeAngelis, Executive Editor, Professional/Trade Division, c/o John Wiley & Sons, Inc., 111 River Street, Hoboken, NJ 07030-5774.

Indexed by ABI/Inform Database (ProQuest) and Environment Abstracts (LexisNexis).

Editorial Production, Wiley Periodicals, Inc.: Ross Horowitz

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SALT CAVERN STORAGE CARRYING THE DAY

Most of the current development activity is focused on salt cavern storage. As shown in **Exhibit 2,** salt cavern projects accounted for 58 percent of development activity, while depleted reservoirs made up 39 percent, and the remainder, primarily aquifer storage, equalled 3 percent.

Depleted reservoirs are used mainly for seasonal injection and withdrawal because gas is normally injected and withdrawn relatively slowly. As a result, natural gas local distribution companies (LDCs) are primarily interested in depleted reservoir storage. Seeking supply reliability and ensuring access to gas supply to serve peak winter season needs, LDCs control or contract primarily for depleted reservoir and aquifer storage.

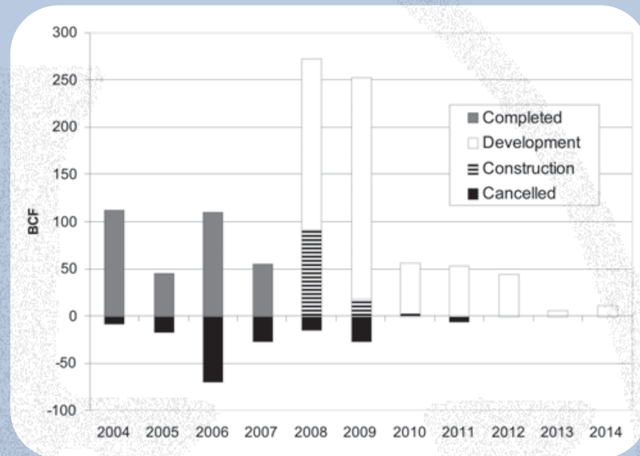
Located almost exclusively in the Midwest, aquifers' water drive can provide greater withdrawal speed than typical reservoir storage, but the operation can be complex and costly. Salt cavern storage is much more flexible in operation than reservoirs or aquifers but is limited by geology to the Gulf Coast (**Exhibit 3**), where naturally occurring salt domes exist. (Bedded salt provides similar opportunity on a limited scale in areas in the Northeast and western North America.)

The focus on salt cavern storage development has lead to a surge in the amount of development activity in just a handful of Gulf Coast states, as illustrated in **Exhibit 4**. Due to the geological location of underground salt domes along the Gulf Coast and the focus on salt cavern storage development, the states of Alabama, Louisiana, Mississippi, and Texas comprise over three-quarters of all working gas capacity development.

Because the flexibility of salt cavern gas storage can be used to rapidly inject and withdraw inventory . . . it has become highly attractive for traders.

Because the flexibility of salt cavern gas storage can be used to rapidly inject and withdraw inventory—in some cases up to 1 billion cubic feet a day or more at a single cavern—it has become highly attractive for traders that want to capture value from daily and monthly natural gas price volatility. The slower speed of injecting or withdrawing gas from many depleted reservoir fields makes it more difficult to extract this value from short-term gas price volatility.

Exhibit 1. U.S. Natural Gas Storage Development



With the build-out of natural-gas-fired power generation capacity during the merchant boom of the late 1990s through 2001, power generators became a significant potential storage customer, mainly to support daily balancing requirements on pipelines.

From 1999 through 2001, approximately 200,000 megawatts of new natural-gas-fired generation was installed in the United States. While dispatch of these gas-fired power plants is highly variable and weather-dependent, on average since 1999, summer period natural gas demand is up by about 6 billion cubic feet a day due to

Exhibit 2. U.S. Gas Storage Development by Type of Storage

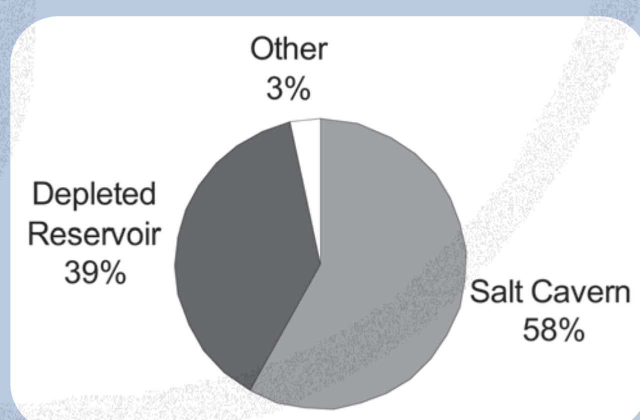


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Exhibit 3. Existing Natural Gas Storage Projects

this new capacity. Increasingly, this new natural-gas-fired power generation capacity is pushing a "dual peak" in natural gas consumption as the bulk of generation occurs to meet summer cooling loads. Already, the United States has seen net-withdrawal weeks from gas storage in summer periods that were unheard of several years ago (the traditional storage injection period lasts from April to October).

With a sharp rise in natural gas prices and a growing recognition that many power markets were overbuilt, in 2002 the merchant power boom came to a crashing halt. The next several years, natural gas was out of favor as a power generation fuel, but due to continued demand growth for electricity and long lead times, high construction costs, and permitting difficulties for coal and nuclear plants, natural-gas-fired power generation is making a strong comeback.

Increasingly, it appears that carbon regulation is a matter of timing. An R.W. Beck study on the impact of carbon regulation found that a carbon price of $30 to $50 a ton would lead to up to 50,000 megawatts of additional natural-gas-fired capacity. The increase could boost demand by up to 2 trillion cubic feet a year and increase average Henry Hub natural gas prices by 20–25 percent. However, the exact timing and level of this demand push from carbon regulation remains subject to a large degree of uncertainty.

Meanwhile, throughout the United States a dramatic increase of renewable power sources—mainly wind and solar—is under way, in large part in response to state-level mandatory renewable portfolio standards (RPSs). Some form of RPSs are in place in most states, and the amount of power consumption covered by these states is about half of total U.S. power demand. Even without federal mandates for RPSs, it is clear that wind and solar capacity will continue to increase around the country.

These renewable resources will create a further reliance on natural-gas-fired capacity to firm up these intermittent power sources and ensure grid reliability and stability. An important consideration is that very little of the amount of installed renewable power generation can be considered capacity because of the uncertainty around when wind or sun power will be available, and in general, historical studies of wind and sun resources typically show only 30–35 percent dispatch. For utilities to meet reserve margin goals and reliability standards, many need additional dispatchable generation resources—with the choice clearly in favor of natural-gas-fired capacity.

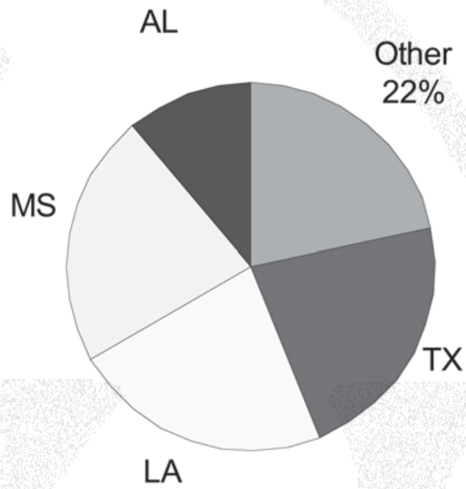
Over the past decade, both the industrial base and power generation sector has lost a significant amount of its ability to switch fuels between natural gas and petroleum fuels. As a result of plant closures and tighter air permit restrictions, many industrials and power generation plants do not have an ability to fuel switch—another reason for companies to safeguard their gas supply by building or acquiring storage.

While petroleum is relatively expensive compared to natural gas on a Btu basis, even current oil price levels have an impact on natural gas markets. This impact is because even during peak demand periods for natural gas there is less demand elasticity, leading to greater natural gas price volatility. Of course, this tight supply is also leading to greater recognition on the part of end-users of the need to "firm up" natural gas supplies, especially for power generation loads. Thus, new natural gas storage assets are part of this focus on improving the reliability and flexibility of natural gas deliveries.

CAUSES FOR INCREASED STORAGE DEMAND—INCREASED LNG IS NUMBER ONE

However, the major driver for the surge in Gulf Coast salt cavern development over the past few years were the numerous liquefied natural gas (LNG) import terminals proposed in the United States. A few years ago, many industry analysts expected LNG to rapidly take up market share in the United States as regasification terminals were built. A frenzy of LNG terminal development was under way at the time, with at one point over 40 new terminals announced covering every coastal region. The new supply was supposed to form a neat wedge to fill the gap between growing domestic demand for gas and declining domestic production.

Exhibit 4. U.S. Storage Development by Location

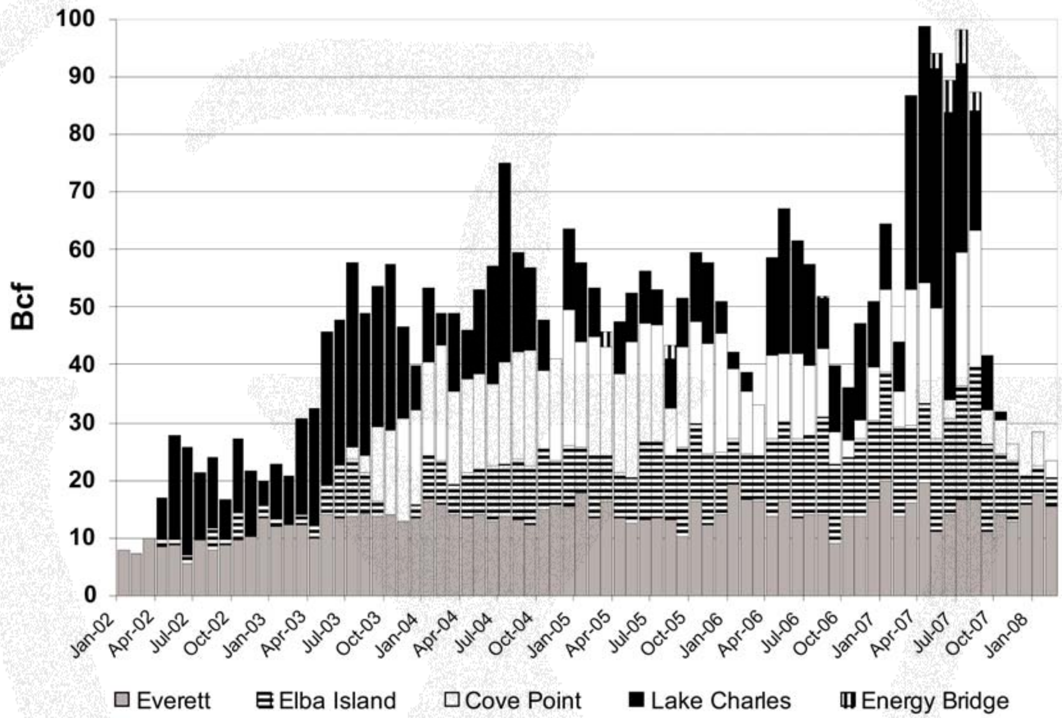


Over the past several years, it became clear that onshore LNG terminals were going to face difficult permitting hurdles anywhere outside the U.S. Gulf Coast, and the only new onshore terminals currently under construction in the United States are the four new terminals located in Texas and Louisiana (Freeport, Sabine Pass, Golden Pass, and Cameron). Along with the expansion of the Lake Charles terminal in Louisiana, the potential deliverability of over 10 billion cubic feet a day in a narrow 150-mile area along the Gulf Coast drove a significant amount of downstream infrastructure including pipeline headers and gas storage.

One example of the rapid increases in storage asset valuation and the money flowing into the sector was the late 2007 acquisition of the Mississippi Hub salt cavern gas storage development project by EnergySouth for $140 million. The project ultimately could include three or four storage caverns that would allow for the storage of up to 40 billion cubic feet of natural gas and daily injection and withdrawal of up to 2 billion cubic feet a day. To move that much gas, the project plans to build a large pipeline header system to connect with multiple local and interstate systems.

When fully built out, the Mississippi Hub may entail investment of over half a billion dollars. However, success is far from guaranteed. Energy South acquired the project when still in early stages with no existing customer contracts.

Exhibit 5. U. S. LNG Imports by Terminal



Source: Energy Velocity

Essentially, Energy South's $140 million acquisition was the price of entry into a high-stakes game of poker. And the wild card is LNG.

MORE STORAGE IN THE CARDS FROM INCREASED PRICE VARIABILITY

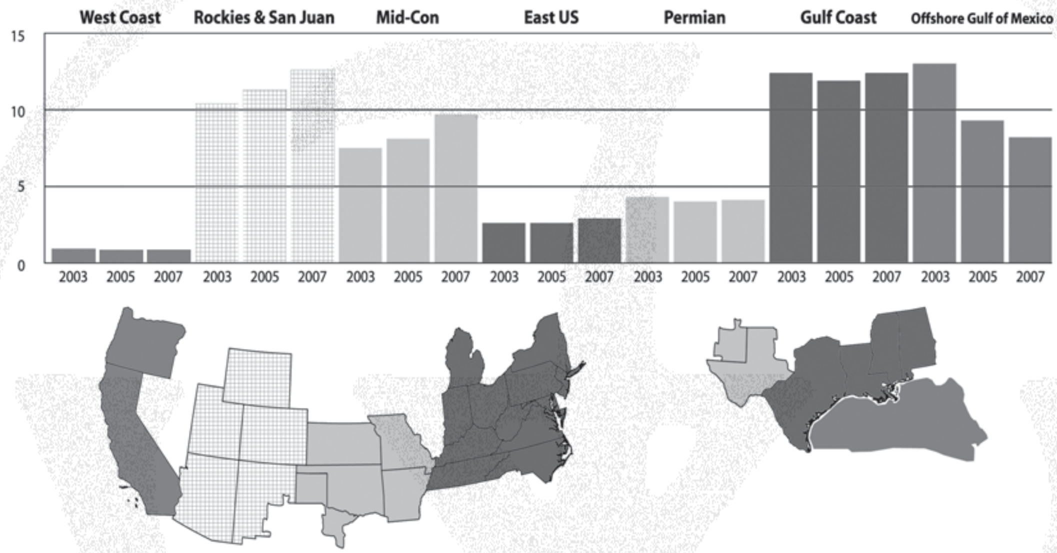
Henry Hub natural gas market prices have steadily marched upward over the first several months of this year and recently zoomed past $10 a million Btu's in April defying the typical seasonal pattern. Because all of the original four U.S. LNG import terminals have been recommissioned and in operation since about 2002 and a new offshore LNG terminal has been added, Henry Hub prices at these levels would have been expected to draw a surge of LNG from around the globe, which would help moderate market prices here.

However, not a single cargo of LNG has arrived at the Lake Charles, Louisiana, LNG terminal since last fall. (See **Exhibit 5**.) The location of the Lake Charles terminal near Henry Hub along the oil-and-gas-infrastructure-rich Gulf Coast makes Lake Charles an ideal terminal for short-term or "spot" cargoes. However, while U.S. natural gas prices have increased, they have failed to match prices in Europe and Asian markets, which have surged along with crude oil prices. Crude oil prices are used in long-term gas supply contracts in many foreign markets. As a result, any swing or spot cargoes of LNG have headed to other countries where suppliers can achieve higher profits.

The practical absence of spot LNG cargoes over the past winter is having an impact across the U.S. energy market. Recently, Cheniere Energy, a leading independent player in U.S. LNG terminal development, was downgraded by equity analysts after the company announced it was looking to sell assets to raise cash. Cheniere was counting on greater supplies of LNG being available to help it monetize some of the 2 billion cubic feet a day of regasification capacity it owns at the Sabine Pass, Louisiana, LNG terminal.

It is now clear that the LNG story is going to be much more complex. Most large European and Asian natural gas markets are even more sea-

Exhibit 6. U.S. Gas Production by Basin 2003–2007



Shown in Billion Cubic Feet Per Day • Source: R. W. Beck and Lippman Consulting

sonal than the U.S. market, and Europe and Asia have very little underground natural gas storage relative to demand. Therefore, European and Asian buyers make long-term commitments to LNG to ensure adequate supply during peak periods but have limited flexibility to take cargoes for future needs. As the global market for LNG expands, the role will grow for the United States to take off-season cargoes. Of course, this role as the world's "market of last resort" is secondary in nature, and in the event of tightness in global LNG supply, U.S. LNG imports will dry up rapidly, making projections for future imports highly uncertain.

The reality is that for the time being North America remains essentially self-sufficient in natural gas, with nonconventional production more than compensating for declining production from traditional domestic and Canadian supplies. (See **Exhibit 6**.) Of course, the shift to nonconventional production has price implications given the significantly higher break-even cost of most shale, tight, and coal bed methane production.

With surging nonconventional gas production from Texas, Midcontinent, and other shales along with Rockies coal bed methane, massive amounts of new pipeline infrastructure are moving forward to link these new domestic gas supplies to Northeast and Southeast growing natural gas markets. As a result of these shifts, storage developers have started to shift their focus back to market areas. While this shift includes a return to depleted reservoir storage development in the Northeast, the announced projects tend to be relatively high deliverability with capability for multiple cycles of working gas.

It is clear that new storage—whether salt cavern or depleted reservoir—is mainly focused on responding to gas price volatility. While the current pause in LNG imports has created challenges for some storage developers, trends in U.S. natural gas supply and demand strongly suggest higher levels of price volatility in the future, which supports investment in "high performance" gas storage that provides high deliverability and multiple cycles of working gas capacity.

Overall, the intense amount of development activity and investment in natural gas storage infrastructure is part of a transformation of the U.S. natural gas industry from a continental market to a global market interconnected by LNG. Activity is also driven by the transformation in U.S. electric markets as they grapple with complex environmental and climate-change issues.

Given the scale of these transformations, it would be unwise to expect them to be orderly or smooth.

 DOI 10.1002/gas /

Natural Gas Price Volatility

Veljko Fotak, Scott C. Linn, and Zhen Zhu

Volatility of energy prices, while viewed by some investors as offering the potential for speculative gains, conversely can be a nightmare for companies who are major users of energy.

Fluctuations in domestic U.S. natural gas prices in particular continue to attract considerable attention and cause much consternation. Daily futures price changes of 5 percent or more are not unusual, nor is the presence of irregular volatility within the trading day. Such volatility can arise from numerous sources but tends to be driven by new information.

Nevertheless, contrast of two periods indicates that volatility as a whole may be decreasing, owing to several new trends.

CLERICAL ERROR CREATES $1 BILLION VALUE CHANGE

An example will help to illustrate this practical association. On November 24, 2004, the market was expecting the Energy Information Administration (EIA) to report a drawdown of natural gas in storage of between 13 and 25 billion cubic feet from the previous week. Instead, the EIA reported a drawdown of 49 billion cubic feet, which prompted the front-month futures price to soar by $1.018 a million Btu's, a 15 percent jump. During the next week, the market, suspecting that there might have been an error in the data, began revising the price downward, causing a price reversion of roughly 7 percent.

On December 1, the EIA revised the previously released information to a 17-billion-cubic-foot drawdown, citing a clerical error by a contract employee at Dominion Transmission as the reason for the previous inaccuracy. The market immediately gave up the remaining 8 percent of the gain upon release of the revised report. The impact of these events has been estimated at an absolute swing in overall contract values on the order of $1 billion.

While events of this magnitude are rare, it is nonetheless common to observe increased price volatility around the release of information impacting the natural gas market. These surges are often the result of market participants being surprised by new information contained in a news release pertaining to the natural gas or petroleum markets. We speculate that market participants do not always interpret the information precisely in the same fashion, leading to excess volatility.

Price volatility is a central characteristic of the natural gas market.

In other words, price volatility is a central characteristic of the natural gas market. Understanding the factors that create volatility is the key to shaping effective strategies focused on controlling exposure to the often capricious behavior of this harsh taskmaster. In what follows, we present a review of recent short-term price volatility in this market with special emphasis concerning how volatility is influenced by two recurring sources' information.

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  / DOI 10.1002/gas

BEHAVIOR OF NATURAL GAS PRICE VOLATILITY

To say the least, price volatility in the natural gas market is anything but monotonous. We present an overview of the behavior of short-term price volatility, emphasizing volatility within the trading day as well as on a daily basis. Our focus is on the volatility of settlement prices for the NYMEX front-month contract during a recent period of history (June 1, 2002 through January 31, 2008). NYMEX changed the opening time for natural gas futures trading from 10:00 a.m. EST to 9:00 a.m. EST effective February 1, 2007. Trading closed at 2:30 a.m. EST during the calendar period we examine.

Price volatility in the natural gas market is anything but monotonous.

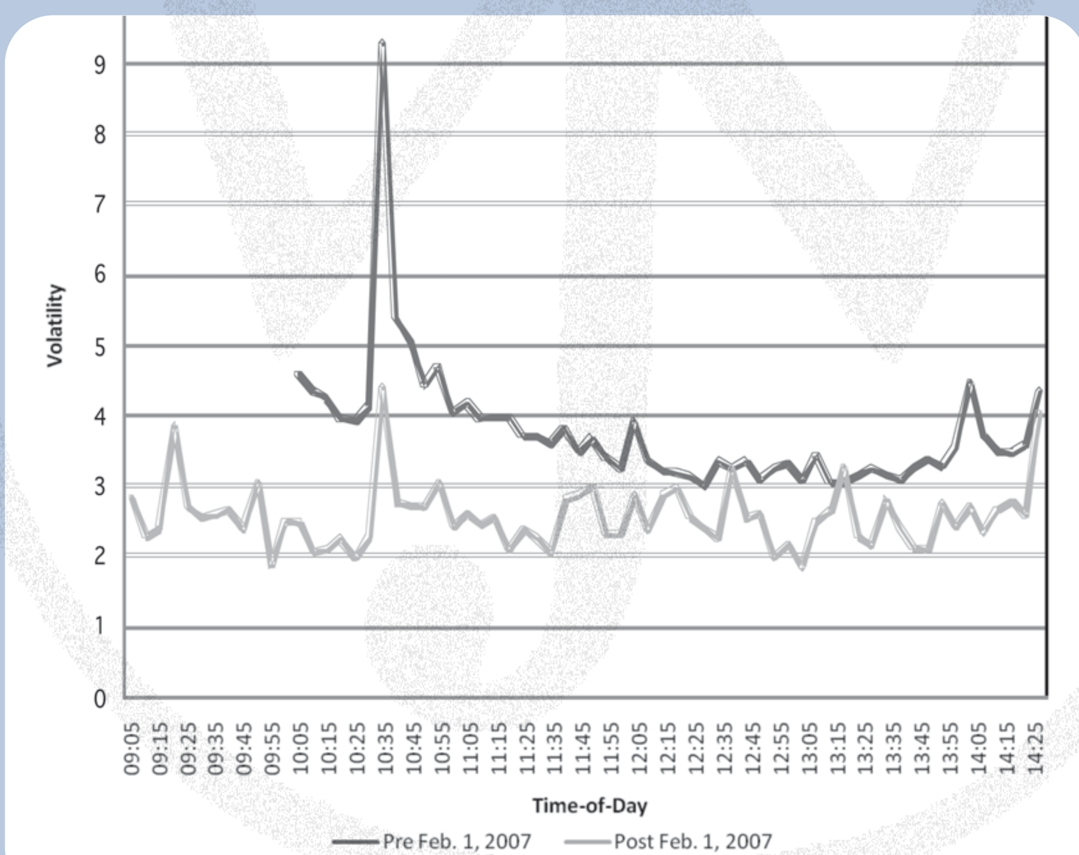
We begin with a presentation of the behavior of volatility within the trading day.[1] The day is divided into five-minute intervals beginning at 9:00 a.m. EST and ending at 2:30 a.m. EST.

We compute price volatility in the following manner.[2] First, we measure the continuously compounded percentage change in the price over each five-minute interval for each day. We therefore have a history of logarithmic price changes for each interval assembled over the calendar days we examine.

Then we compute the standard deviation of the log price changes for each interval. For instance, our calculations produce a history of log price changes for the 10:10–10:15 a.m. interval, one for each day in the sample period. The standard deviation of the log price changes for the 10:10–10:15 a.m. interval is then computed using the history of log price changes for that interval. The computed standard deviation is our measure of price-change volatility for the interval.

We multiply each standard deviation by 10^3 for purposes of display in the exhibits. **Exhibit 1** displays the price volatilities for each of the

Exhibit 1. Natural Gas Volatility by Time of Day



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consecutive five-minute intervals of the day for the NYMEX front month futures contract for the full sample period. The exhibit presents two sets of volatilities, those for the period prior to February 1, 2007, and those for the period after.

Exhibit 1 shows several important features of volatility during the period we study. First, the general level of volatility has fallen. Second, both time periods are associated with a spike in volatility around 10:30 a.m. Although consistent with the overall reduction in volatility, the spike during the second calendar period is much smaller.

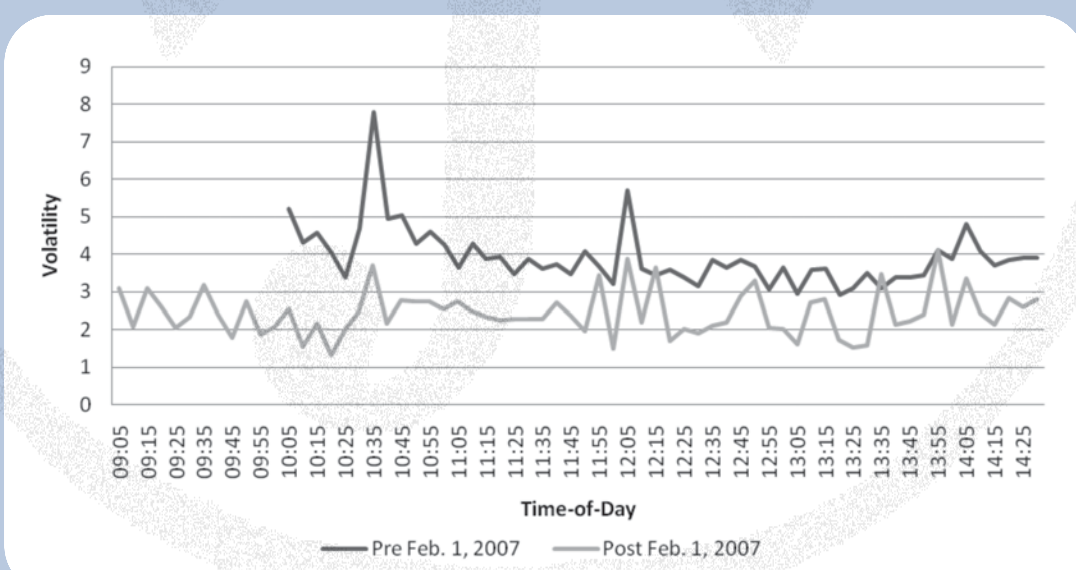
Third, there is a noticeable U-shape to the volatilities during the first period following the 10:30 a.m. spike. The second calendar period exhibits no such U-shape. However, both periods exhibit a modestly larger volatility at the end of the day. A possible explanation for the end-of-day upturn in volatility could be a disproportionate number of short-term traders in the market who close their positions near the end of the day. One explanation for the flattening in the pattern during the second calendar period may be an increase in overnight trading, which has picked up over the course of the time period we examine.

Exhibit 1 does not differentiate between the days of the week. **Exhibits 2** and **3** present the within-day volatility patterns for Wednesday and Thursday. Notice that both days exhibit a spike in volatility around 10:30 a.m. Inspection of the remaining days of the week (not reported here) shows no such behavior. It is clear that the spike in volatility observed at 10:30 a.m. illustrated in Exhibit 1 is due to spikes on both Wednesday and Thursday.

Consistent with Exhibit 1, Exhibits 2 and 3 show there was a marked decrease in volatility between the two calendar time periods. Further note that volatility around the open on both Wednesday and Thursday tended to be smaller during the first calendar period. One explanation may have been that the market participants were collectively holding their breath in anticipation of the release of the respective oil and gas reports. This pattern does not, however, seem to be present for the second and more recent calendar period.

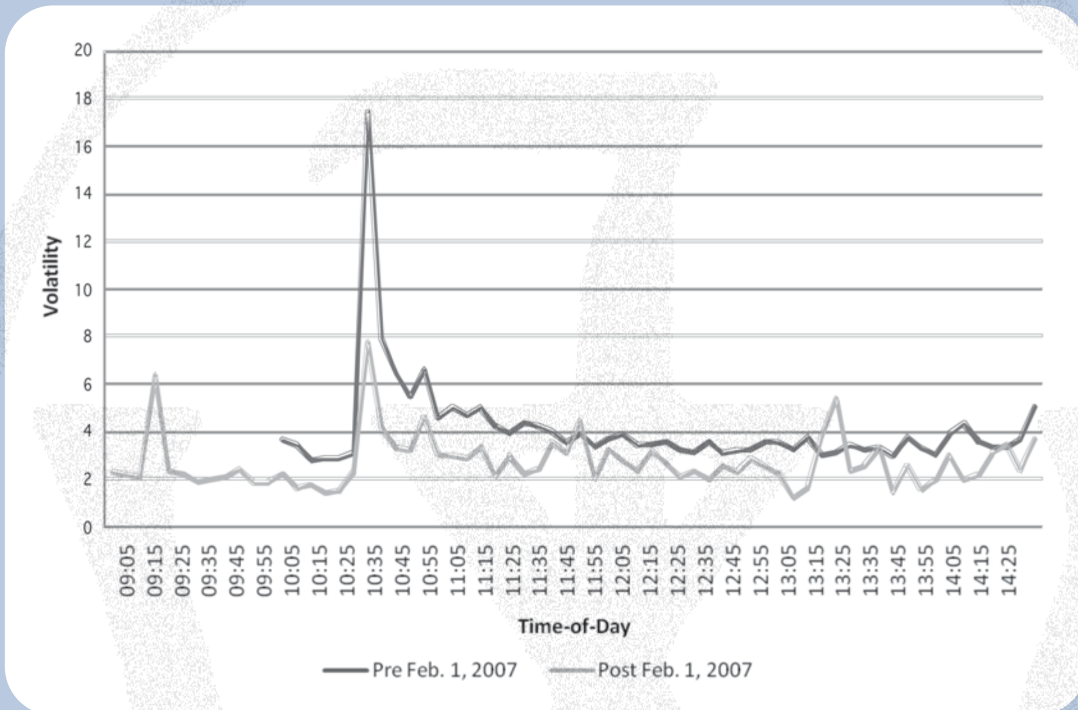
We conclude this section by highlighting the overall daily price volatility for each day of the week. Here we are measuring the volatility of the change in the close-to-close settlement price. **Exhibit 4** presents the daily price volatility by the day of the week. Thursday exhibits the overall largest daily volatility. While Wednesday exhibits a volatility surge at 10:30 a.m.. as shown in Exhibit 3, overall the daily volatility on Wednesday during the most recent calendar pe-

Exhibit 2. Natural Gas Volatility by Time of Day Wednesday



  / DOI 10.1002/gas

Exhibit 3. Natural Gas Volatility by Time of Day Thursday



riod is not noticeably different from the other days of the week aside from Thursday.

NATURAL GAS AND PETROLEUM INVENTORY REPORTS

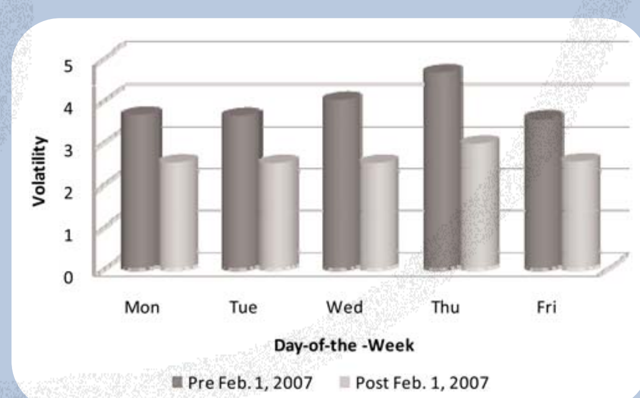
A natural question arises from the volatility patterns shown in Exhibits 1–3. What event or events are associated with the larger volatilities around 10:30 a.m. on Wednesdays and Thursdays?

As it happens, there are two important pieces of information about the physical natural gas and petroleum markets that are released routinely at 10:30 a.m. on these days. Specifically, the larger volatilities occur around the time of day the Energy Information Administration (EIA) of the Department of Energy releases information about petroleum inventories and natural gas in storage. On Wednesdays at 10:30 a.m. EST, the EIA releases the *Weekly Petroleum Status Report,* and at 10:30 a.m. EST on Thursdays, the EIA releases its *Weekly Natural Gas Storage Report* about the amount of natural gas in storage. These reports are updated weekly and report data as of the prior Friday.[3]

The oil and gas inventory reports are followed closely by market participants, as these data provide timely information about current supply-and-demand conditions. As an illustrative example, consider the nature of supply and demand for natural gas.

Natural gas production is relatively smooth over the course of the calendar year. In contrast,

Exhibit 4. Natural Gas Price Volatility



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the demand for natural gas is seasonal, being heavily influenced by the weather. Natural gas in storage tends to act as the marginal source of supply mitigating unexpected changes in production or demand. The change in natural gas in storage from one week to the next is therefore by its nature uncertain, but market participants form beliefs about the number.

If the expected change in the level of gas in inventory is lower than what is revealed by the EIA storage report, it suggests that an excess will be available to meet future needs. The reverse would be true if the actual change was lower than what was expected. Therefore, the change in storage is a much-forecasted quantity by market participants. However, it appears that market participants do not agree beforehand about how the quantity in storage will change. These different forecasts lead to surprises when the EIA releases its numbers and also lead to volatility as participants move to correct their positions upon learning the news. Thus, we might expect to observe an association between the price volatility observed at 10:30 a.m. on Thursdays and the release of the natural gas storage report by the EIA.

Different forecasts lead to surprises when the EIA releases its numbers and also lead to volatility as participants move to correct their positions.

INFORMATION ABOUT THE OIL MARKET

Even though the substitutability of oil for gas or gas for oil is limited by the current state of technology, it is hard to conclude that the high natural gas price volatility observed at 10:30 a.m. on Wednesday when the *Petroleum Status Report* is released is not in some way connected to that information. While we do not directly investigate the connection between the oil and gas markets, one possible explanation is that the information in the *Petroleum Status Report* creates volatility in the oil futures market and this spills over to the natural gas market. Given the physical proximity of trading in natural gas and oil futures, this is certainly a plausible explanation.

VIEWS ON THE REDUCTION IN VOLATILITY

There are varying views about this subject.

Increased Information

While the impact of surprises on natural gas futures price changes is unequivocal, there is increasing evidence that in recent years, the overall volatility in these markets has declined. The decline is evident in each of the exhibits presented earlier. One belief is that volatility has declined as a result of the increasing availability of better data about the supply and demand for physical natural gas.[4] In particular, there is increasing availability of data about natural gas pipeline flow statistics.

Volatility has declined as a result of the increasing availability of better data about the supply and demand for physical natural gas.

The increased information stems from Federal Energy Regulatory Commission Order 637 (February 9, 2000), which imposed the requirement that interstate pipelines post extensive daily data on their Web sites about the flows of natural gas through their systems. In and of themselves, these individual postings are only truly informative if the data can be easily aggregated. Several commercial innovators have risen to the task and now make aggregated as well as disaggregated data commercially available.[5] Some market observers have argued that the availability of such data has reduced the size of surprises arising from the natural gas storage report and has reduced overall volatility.[6]

Liquidity

The exhibits already presented show that a marked reduction in volatility has occurred in natural gas prices. Aside from the increased information flow mentioned above, we believe that this decrease may in part be associated with an increase in overall market liquidity. **Exhibit 5** presents data about open interest that parallels the decline in volatility. We make no attempt to draw a causal link between the change in open interest and the change in volatility, but suspect there may be a connection.

Exhibit 5 presents the average weekly total open interest for the NYMEX natural gas futures contracts for the calendar periods before and after February 1, 2007. The data supporting this table were obtained from Commitments of Traders Reports prepared by the Com-

Exhibit 5. Open Interest NYMEX Henry Hub Natural Gas

	Average Weekly Open Interest (OI)	Pct of OI-Noncommercial Long	Pct of OI-Noncommercial Short	Pct of OI-Noncommercial Spread
Pre Feb 1, 2007*	528447	9.86%	13.30%	48.95%
Post Feb 1, 2007*	815074	11.00%	17.64%	46.99%

*6/3/2003 through 1/31/2007
Source: Various Commitments of Traders Reports, CFTC (http:www.cftc.gov/)

modities Futures Trading Commission (CFTC). The exhibit clearly shows a dramatic increase in open interest between these two periods of time. In fact (not reported), there are increases in open positions in all position categories—long, short, spread, commercial, and noncommercial. These preliminary statistics suggest that the reduction in volatility and the increase in volume (measured as open interest) are connected. One possibility is that the increase in open interest is a proxy for an increase in market liquidity.

Reduction in volatility and the increase in volume (measured as open interest) are connected.

Speculative Activity and Volatility

There has been an intense conversation over whether speculation in the natural gas market, in particular by hedge funds, is the reason for volatility. The question has attracted considerable attention from users of gas as well as government policymakers. While we do not attempt to answer the question here, we offer several observations about the matter. Exhibit 5 can help us here.

There has been an intense conversation over whether speculation in the natural gas market, in particular by hedge funds, is the reason for volatility.

The CFTC classifies hedging activities as commercial and other speculative trading as noncommercial. While these are rather gross classifications, the conjecture is that hedge fund activity will be reflected in the noncommercial category. If speculative activity and price volatility are positively related, and if the reduction in volatility is due to a reduction in speculative activity, then we would expect to observe a reduction in noncommercial activity between the two calendar periods studied. However, the statistics in Exhibit 5 show that noncommercial activity as a fraction of the total increased after February 1, 2007. This conclusion seems to be at odds with the notion that increased speculative activity leads to higher price volatility.

The conclusion seems to be at odds with the notion that increased speculative activity leads to higher price volatility.

WILL VOLATILITY CONTINUE TO DECREASE?

It remains to be seen where the limiting behavior of natural gas price volatility will settle.

NOTES

1. The source of the futures price data examined in this article is Tick Data, a division of Nexa Technologies, Inc. (http://tickdata.com/).
2. We examine the period 1/1/1999 through 10/31/2002 in our earlier study, Linn, S., & Zhu, Z. (2004). Natural gas prices and the Gas Storage Report: Public news and volatility in energy futures markets. *Journal of Futures Markets,* 24(3), 283–313, using similar methods to those presented here.
3. Details about these reports and the information they contain about physical petroleum and natural gas can be found at the Web site of the EIA, http://www.eia.doe.gov/.
4. Kaminski, V., & Braziel, R. (2007, August). Going with the flow. *Energy Risk,* pp. 72–77.
5. For instance, Bentek Energy (http://www.bentekenergy.com).
6. See note 4.

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Still a Relationship Between Crude Oil and Natural Gas Prices?

Bill Trapmann

We at the Energy Information Administration (EIA) love a good debate—particularly on issues of energy and prices. Recently, we have been trying to figure out if a shift or evolution in market forces has led to a "decoupling" of crude oil and natural gas prices in the United States.

Proponents of a relationship between crude oil and natural gas prices argue that competitive market forces, especially on the demand side, maintain a relationship between the prices. Oil and natural gas are substitute fuels primarily in the electric generation and industrial sectors. Dual-fired units can burn the less expensive fuel, subject to environmental restrictions. However, potential fuel switching is not limited to dual-fired units. Changes in consumption patterns also occur systemwide based on relative fuel prices, among units either operated by a single company with multiple plants or operated by competitors. The potential to shift consumption based on relative prices would operate to mitigate excessive price differentials between natural gas and oil.

The opposing view questions whether the fuel switching that remains today still can affect the market given that the diminishing number of dual-fired units, on a relative if not absolute level, limits fuel competition at the margin. The increasing tendency for monthly crude oil and natural gas prices to diverge supports this argument (**Exhibit 1**). A more stable price difference in the 1990s was broken with a few short-lived periods when prices either diverged sharply or tended to converge. The 1990s crude oil price premium reflected factors like the higher costs of natural gas processing, storage, and transportation, resulting in a lower commodity price for natural gas. Since 2000, natural gas prices occasionally exceeded crude oil prices but most recently dropped relative to oil to levels last seen in the early 1990s (**Exhibit 2**).

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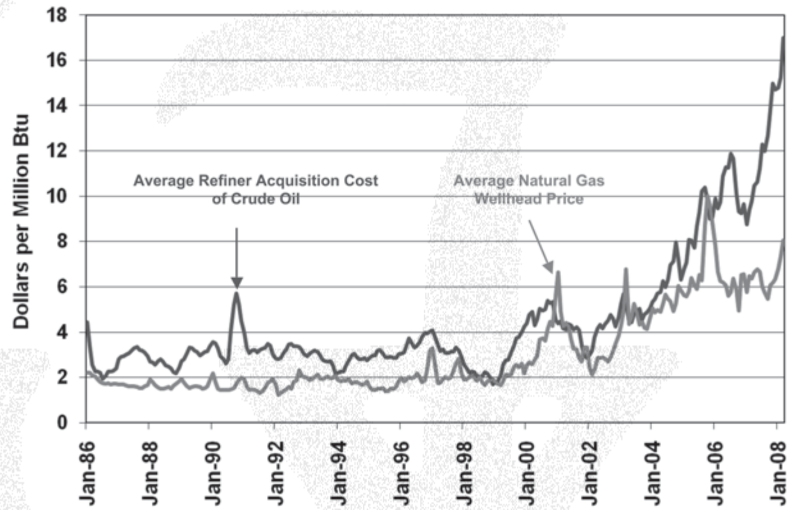
In recent years, natural gas has sold at a discount to both distillate and fuel oil. Fuel switching toward natural gas is unlikely to be constrained by environmental permit conditions and was presumably pursued to the maximum extent during such periods, but oil and gas prices still diverged.

SEARCH FOR RULES OF THUMB

Traditionally, analysts who favor a price relation have tried to provide a relatively simple rule of thumb to relate oil and gas prices.

One example, based on historical data, is the 10-to-1 rule, which states that the price of crude oil in dollars a barrel is about 10 times that of natural gas in million Btu's.[1] However, the 10-to-1 rule does not reflect fluctuations in relative prices. For example, from 1986 to 1994, natural gas prices relative to crude oil prices varied from 29 percent to 97 percent (Exhibit 2). (A 60 percent parity level is equivalent to a 9.7 ratio—close to 10 to 1.) Market fluctuations may cause short-term deviations from the mean, but as long as the ratio is mean reverting, an analyst can argue that there was a long-term relation of approximately 60 percent from 1986 to 1994. However, the price parity level rose to an average of 68 percent in the last half of the 1990s, equivalent to an 8.5-to-1 ratio. The 6.9-to-1 ratio in the early 2000s (84 percent) indicates that perhaps a single ratio cannot do the job.

Exhibit 1. Monthly Crude Oil and Natural Gas Prices (January 1986–March 2008)



Source: Energy Information Administration

The ratio of crude oil price per barrel to natural gas in dollars per million Btu's would be approximately 6 to 1 if prices were based strictly on the thermal content of each fuel.[2] This ratio's innate appeal is belied by the observation that prices at approximate thermal parity, while increasingly frequent, still are not common. Monthly natural gas prices at 100 percent or more of the crude oil price occurred only 13 times in 2000–early 2008, a rate approximately equal to three times every two years. Relative prices reached at least 90 percent only 21 percent of the time.

TECHNICAL ANALYSES

Analysts have addressed the issue of a relation between oil and gas prices using statistical techniques on time-series data, with differing results. Certain studies claim that data do not support a relation or support only a weak relation between the prices.[3] Other studies, however, including one by the EIA,[4] find that there is a stable, long-term relation between crude oil and natural gas prices.[5] These studies argue that short-term deviations occur, but markets operate to return prices to the long-term trend. Price deviations may be driven by a wide variety of factors, including global oil market fluctuations, extreme weather events, natural gas in storage, and disruptions to natural gas supplies. When these factors are recognized in the analysis, a stable, long-term underlying relationship can be established. These studies find that natural gas prices depend upon crude oil prices, but not the reverse.

According to this view, the two fuel prices are like someone walking a dog on a leash. At any particular time, the distance between the walker and the dog may vary, but the distance has a limit, and both follow a similar path over time.

IS THERE A RELATIONSHIP OR NOT?

If there is a relationship between crude oil and natural gas prices, it is complex. Certainly, people who make rational economic decisions will be motivated to switch fuels at times. However, regardless of motivation, consumers may not have sufficient ability to switch in order to influence prices. The opportunity and the speed to switch are factors that make the price relationship complex. For example, individual customers may be reluctant to switch promptly when adverse prices arise because if the relative prices are not sustained, there will be costs incurred to switch back. If the adverse prices are short-lived, the lowest-cost option might be to continue consuming the higher-priced fuel for a short period.

Liquefied natural gas (LNG) trade between the United States and foreign suppliers also may

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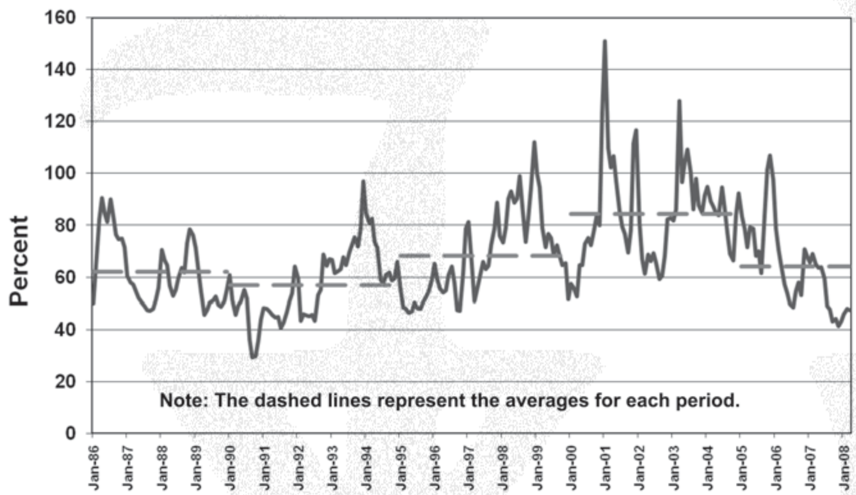
Exhibit 2. Monthly Ratio of Natural Gas to Crude Oil Price (January 1986–March 2008)



Note: The price ratio was calculated using prices in dollars per million Btu's for both fuels.
Source: Energy Information Administration.

support a price relationship. Much of international LNG trade is based on prices tied to crude oil. As the price of crude oil increased strongly this past winter, U.S. LNG imports fell off because (relatively) lower U.S. natural gas prices were not sufficiently competitive to entice LNG toward U.S. terminals. Consequently, preliminary data show that U.S. LNG imports in the first three months of 2008 are roughly half of the volumes received in the first quarter of 2007, lowering average daily supplies by more than 1 billion cubic feet a day during the period. The lower natural gas supply in the United States results in upward price pressure, working to restore a long-term relative position of prices.

CONCLUSION

There is not a definitive argument for or against the existence of a stable, long-term relationship between crude oil and natural gas prices in the United States. The issue appears to be that there are different opinions regarding the adequacy of market mechanisms to establish and maintain relative prices at a given level or at least within a limited range. Historical data suggest that there may have been a loose relation between the two price series in the past, but with a widening difference in recent years. Some cite this wider difference as evidence that the prices are now decoupled. However, divergence between the prices in the past may be explainable as the result of variation in a number of market-related variables. If prices remain coupled, we could expect a return to a tighter range of oil and gas prices over the next year or two (absent further strong, exogenous price shocks that would delay or impede the needed market adjustment). We should not, however, expect the debate to end any time soon.

NOTES

1. The thermal content of a thousand cubic feet of natural gas is approximately 1.027 million Btu's. Given the rough equivalence of 1,000 cubic feet and 1 million Btu's, use of the rule generally does not differentiate between the two.
2. The average thermal content of a barrel of crude oil is 5.8 million Btu's.
3. See, for example, Bachmeier, L. J., & Griffin, J. M. (2006). Testing for market integration: Crude oil, coal, and natural gas. *Energy Journal,* 27(2), 55–71.
4. Villar, J. A., & Joutz, F. L. (2006, October). *The relationship between crude oil and natural gas prices.* Washington, DC: Energy Information Administration.
5. Some studies analyze the relation between a petroleum product (e.g., residual fuel oil) and natural gas. However, the price of a petroleum product is driven in part by that of crude oil; thus, the findings are consistent.

Most Recent Yearly Figures Show Canada Exported Less, Mexico Imported More

Damien Gaul

Most recent data, on which there was a delay because of the desire to disclose accurately net exports and imports by border trade zone (**Exhibit 1**),[1] show that in spite of some inroads by liquefied natural gas (LNG) (not covered here), Canada is still by far the most important external source of natural gas coming *into* the United States. Conversely, Mexico is growing in the amounts that are taken *out* of the United States.

CANADA-U.S. NATURAL GAS TRADE

U.S. demand as well as Canadian supply dropped.

Summary

Despite steady growth in the prior two years, gross imports from Canada in 2006 declined by nearly 3.0 percent, or 110 billion cubic feet. The decrease in net U.S. imports from Canada was slightly less at 93 billion cubic feet, or 2.8 percent, because of lower U.S. exports to Canada. The decrease in flows between the United States and Canada reflected lower consumption in U.S. market areas. Additionally, Canadian producers active in the Western Canada Sedimentary Basin (WCSB) have been experiencing difficulty in maintaining output in an economic environment of rising production costs and declining well productivity.

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Changing Situation

Growth in U.S. net imports from Canada stalled in 2006 as warm weather resulted in lower demand by residential and commercial consumers in North America overall. The result of the moderate weather was high levels of underground storage in both Canada and the United States, as the natural gas was not transported to market areas to meet heating requirements in population centers.

During the year, gross natural gas imports from Canada decreased in a year-over-year comparison in 9 of the 12 months, resulting in an overall decrease of 110 billion cubic feet, or 3.0 percent. Nonetheless, Canada continued to be the largest source country for natural gas imports to the United States by far, with gross exports totaling 3,590 billion cubic feet, accounting for 85.8 percent of gross imports to the United States.

Canada continued to be the largest source country for natural gas imports to the United States by far.

U.S. exports to Canada, measured on a much smaller scale relative to U.S imports from Canada, flowed primarily through exit points in Michigan. U.S. exports to Canada, equaling approximately one-tenth of imports from Canada, also declined during 2006. U.S. exports to Canada decreased 17 billion cubic feet, or 4.8 percent below 2005 volumes, to 341 billion cubic feet. Nonetheless, this volume was still nearly five times the level measured in 2000, before additional pipeline infrastructure was constructed.

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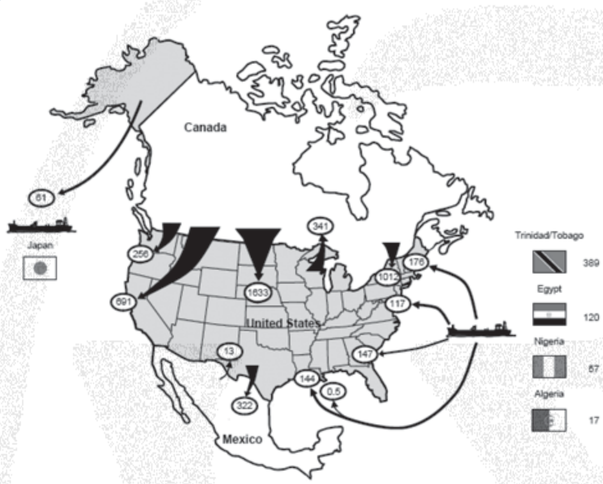
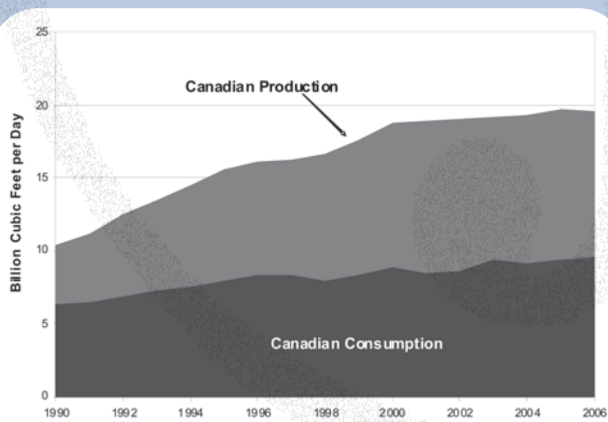
Exhibit 1. Flow of Natural Gas Imports and Exports, 2006 (Billion Cubic Feet)



Source: Energy Information Administration, based on data from the Office of Fossil Energy, U.S. Department of Energy, *Natural Gas Imports and Exports*.

The volume of U.S. imports from Canada has historically reflected overall growth in Canadian production, which has slowed considerably (and even exhibited annual declines in some years). In 2006, Canadian production of 6,681 billion cubic feet (18.3 billion cubic feet per day) was less than 1 percent more than their production of 6,616 billion cubic feet (18.12 billion cubic feet per day) in 2005 (**Exhibit 2**).[2] Most Canadian production originates in the WCSB, where producers reduced large-scale drilling programs midway through the year as natural gas prices began decreasing and costs (including labor) escalated. In 2006, the number of drilled gas wells dropped an estimated 12.3 percent from the previous year to about 13,965 (**Exhibit 3**).[3] Even as Canada is experiencing these supply strains, Canadian domestic natural gas demand for oil sands operations in Alberta and for natural gas–fired power generation in Ontario is increasing.

Exhibit 2. Canadian Natural Gas Production by Consumption and Net Exports, 1990–2006



Source: International Energy Agency, *Natural Gas Monthly Survey*, (July 2007). Online at: http://www.iea.org.

In eastern Canada, deliveries from the Sable Island Offshore Energy Project (SOEP) in Nova Scotia continued to decline, as investment in the region has decreased following disappointing returns to exploration in the area. Although exploitation of discovered fields will continue for some time, and at least one major development (Encana's Deep Panuke development) is planned, expectations for production from the region have diminished considerably since the beginning of this decade. In October 2007, the National Energy Board estimated that deliverability from SOEP will decline by about 11 percent by the end of 2009 to about 370 million cubic feet per day.[4]

Growth of cross-border pipeline capacity has also slowed significantly. In the late 1990s, major new pipeline systems were built to provide outlets to increased Canadian production. However, in the past two years, a total of only 75 million cubic feet per day of capacity has been added, indicating the slowing development of new Canadian production and exports to the United States.[5] Some operators of LNG terminals in Canada intend to both supplement Canadian supply and provide supplies of natural gas for export to the United States. The EIA has tracked up to six proposed LNG regasification plants in eastern Canada and two projects on the Canadian West Coast, for their likely impact on U.S./Canada cross-border trade. Although most of the Canadian LNG import terminals are not proposed for direct reexport of natural gas to the United States, nearly all would have at least an indirect impact on the trade balance, with potential large additions to Canadian aggregate supply.

Canada's first LNG import terminal will likely be operational in late 2008. Irving Oil and Repsol's project in Canaport, New Brunswick, has received all necessary regulatory approvals and has nearly completed construction of three tanks, each with storage capacity of about 2.5 billion cubic feet. The facility will have total sendout capacity of 1.2 billion cubic feet per day in its first phase of operations and use existing and expanded capacity on the Maritimes & Northeast Pipeline (M&NP) to move natural gas into the U.S. Northeast. The pipeline capacity is available, in part, because of the declining production from the SOEP and continued disappointments related to the exploration and development of Sable Island reserves.

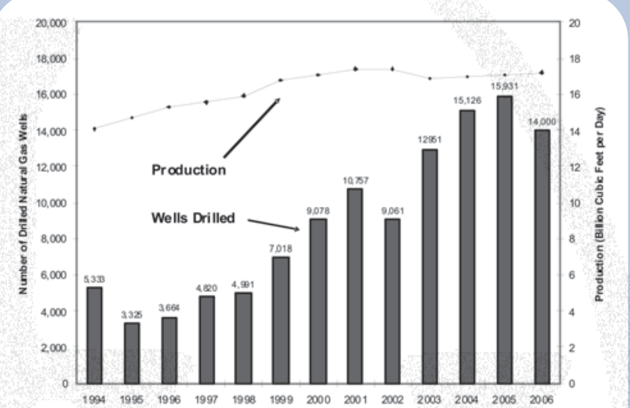
Similar to U.S. domestic natural gas prices, the price of natural gas imports from Canada declined in 2006. The annual average price was $6.70 per million Btu's ($6.83 per thousand cubic feet) for the year, or about 16 percent less than the 2005 average of $7.94 per million Btu's ($8.09 per thousand cubic feet). Prices mostly declined through the year as the market tightness from constrained supplies following Hurricanes Katrina and Rita diminished. The average monthly price for imports from Canada declined from $9.87 per million Btu's ($10.06 per thousand cubic feet) in January to a low of $4.73 per million Btu's ($4.82 per thousand cubic feet) in October. At the end of the year, the monthly average price was $7.45 per million Btu's ($7.59 per thousand cubic feet).

Canadian exports are an important revenue source to that country, representing U.S. $24.5 billion in trade during 2006.[6] This trade value was substantially less than in 2005, when the value of imports was a record $29.9 billion. Because the value of the U.S. dollar in Canada declined between 2005 and 2006, this resulted in a more severe decline for the Canadian gas producer's revenue in Canadian dollars. The record level of revenues in 2005 was supported by a period of extremely high prices, in part because of the effects of Hurricanes Katrina and Rita.

Currently, there are 23 principal entry points for imports from Canada into the United States. For this report, they are grouped into four regions: the Pacific Northwest, the West, the Midwest, and the Northeast (**Exhibit 4**). Imports into all regions but the West declined.

In 2006, the Midwest received the greatest percentage (45 percent) of total natural gas imports from Canada with imports of approximately 1,632 billion cubic feet. The region, which had a decrease in imports of 80 billion

Exhibit 3. Number of Drilled Natural Gas Wells and Production in Canada, 1994–2006



Source: Canadian Association of Petroleum Producers, *Statistical Handbook*. Data available on the Internet at http://www.capp.ca.

cubic feet, or 4.7 percent, from 2005 volumes, includes the largest cross-border pipeline system built in recent years, the Alliance Pipeline System, which has an operating capacity of 1.3 billion cubic feet per day and crosses the border at Sherwood, North Dakota.

About 28 percent of all U.S. imports from Canada were delivered to the U.S. Northeast. U.S. imports into this region declined 16 billion cubic feet, or about 2 percent, to 1,012 billion cubic feet. At the Niagara, New York, border crossing, where the Tennessee Gas Pipeline connects with the TransCanada Pipeline system, volumes declined 36 billion cubic feet to 355 billion cubic feet. Volumes at Calais, Maine, where M&NP crosses the border carrying natural gas from the SOEP, fell 29 billion cubic feet to 106 billion cubic feet because of declining production. Reflecting their proximity to major consuming markets with the highest prices in the United States, border points in the Northeast had the highest prices of the four import regions. The average price for imports into the Northeast was $7.38 per million Btu's ($7.52 per thousand cubic feet), which reflected a decrease of $1.64 per million Btu's ($1.67 per thousand cubic feet).

The West and the Pacific Northwest regions received, respectively, 19.2 and 7.1 percent of total imports from Canada during 2006. Imports into the Pacific Northwest declined by

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24.0 percent, or 81 billion cubic feet, during the year, in part owing to competition from growing production in the U.S. Rockies. However, some of the displaced volumes were likely redirected to the West region (which includes border points with linkages to California markets), where imports increased 10.6 percent on the year to 66 billion cubic feet.

The United States exports natural gas by pipeline to Canada at numerous locations, but most significantly at St. Clair, Michigan, where the Vector Pipeline crosses the border with a capacity of 1.5 billion cubic feet a day. The volume of natural gas exported through the St. Clair point is by far the largest of any export point to Canada. U.S. exports through St. Clair in 2006 were 287 billion cubic feet, while total exports to Canada were 341 billion cubic feet. The total volume of U.S. exports to Canada in 2006 decreased 17 billion cubic feet, or 4.8 percent. The average price of U.S. exports to Canada was $7.20 per million Btu's ($7.34 per thousand cubic feet), 5.9 percent below the 2005 price.

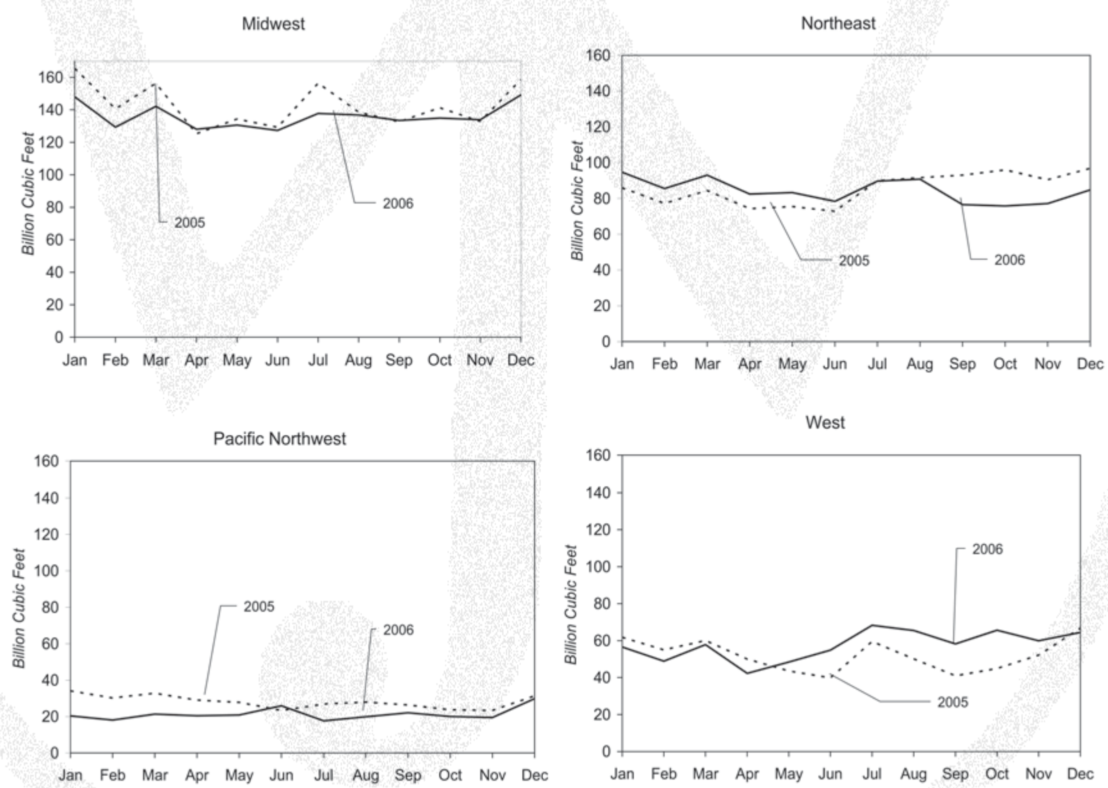
MEXICO-U.S. NATURAL GAS TRADE

Northern Mexico continued to grow and needed more natural gas.

Summary

Net U.S. exports to Mexico rose to 309 billion cubic feet, which was 4.6 percent more than the volume in 2005. Nonetheless, U.S. export volumes to Mexico continued to be considerably lower than the historical high of 397 billion cubic feet, reached in 2004. The 309 billion cubic feet in 2006 from the United States was roughly 16 percent of Mexico's over-

Exhibit 4. U.S. Natural Gas Pipeline Imports from Canada by Regional Point of Entry, 2006



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.
Notes: Flows in the Pacific Northwest region consist of points of entry in the state of Washington. Flows in the West region consist of points of entry in Idaho. Points of entry in Montana, North Dakota, Michigan, and Minnesota comprise the Midwest region. Points of entry in New York, Vermont, and Maine comprise the Northeast region.

all consumption of 1,909 billion cubic feet (**Exhibit 5**).

Increasing Supplies Going South Again After Katrina and Rita

High prices and U.S. supply constraints following Hurricanes Katrina and Rita appeared to have a large impact on Mexican demand in late 2005, resulting in a large decline in U.S. exports to Mexico that year. With prices easing slightly in 2006, exports to Mexico rebounded to almost triple the level in 2000. U.S. exports serve industries and power plants by the U.S.-Mexico border and supplement supplies from Petroleos Mexicanos (Pemex).

Export volumes to Mexico continued to be considerably lower than the historical high of 397 billion cubic feet, reached in 2004.

Mexico has sizable natural gas reserves relative to the country's consumption, but the slow development of these supplies as the result of a lack of investment has increased the importance of U.S. natural gas exports needed to meet growing demand.

Although U.S. exports to Mexico represented an increase of 6 percent over the prior year, volumes in 2006 were still 19 percent below the historical peak of 397 billion cubic feet reached in 2004. In fact, annual declines in Mexican production were reversed in 2003, as greater investment in resource development took hold. Production estimates for 2006 indicated that the improvement in resource development continued with Mexico's state oil and natural gas company, Petroleos Mexicanos (Pemex), increasing production by about 10 percent to about 1,600 billion cubic feet.

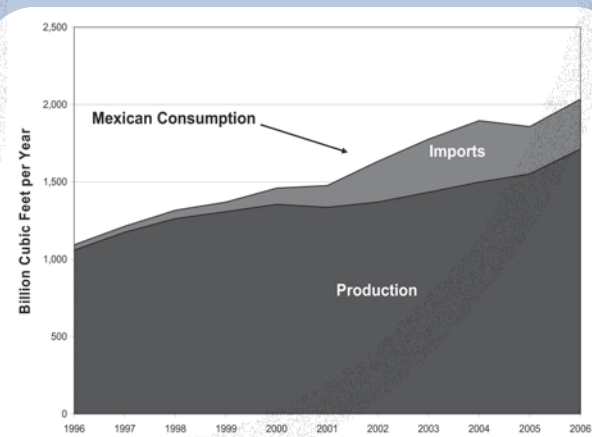
Additionally, Mexican officials continue to press forward with plans to reduce dependence on U.S. imports through developing the country's reserves in conjunction with the construction of LNG terminals. On the country's east coast, one LNG terminal is already active. Altamira LNG, a joint venture of Royal Dutch Shell (50 percent), Total (25 percent), and Mitsui (25 percent), received its first LNG cargo in August 2006. On Mexico's west coast, construction of the Costa Azul LNG terminal is near completion, with operations expected in early 2008. Additionally, at least one more LNG terminal is planned to be built on the west coast, likely in the Manzanillo province.

Under the program, private companies can provide financing and conduct operations associated with a project, but Pemex retains ownership of the commodity.

This movement toward increased domestic production and greater reliance on LNG is part of Mexico's Strategic Gas Plan, formulated by Pemex in 2000. The plan targets increased domestic production through "multiple service contracts" (MSCs) with private companies, as well as imports of LNG to both east and west coasts.[7] The MSCs are meant to comply with the country's constitution, which prohibits foreign ownership of oil and natural gas resources while providing sufficient economic incentive to encourage foreign investment in the oil and natural gas sectors. Under the program, private companies can provide financing and conduct operations associated with a project, but Pemex retains ownership of the commodity. [A detailed analysis of this program and other political factors in Mexican gas supply can be found in Daal, J. (2008, April). Mexico to need help with deepwater, other natural gas projects, *Natural Gas & Electricity*, 24 (9), 1–7. —*Ed.*]

In Mexico, much of the natural gas production is concentrated in the south of the country,

Exhibit 5. Mexican Natural Gas Consumption, Production, and Imports, 1996–2006



Source: International Energy Agency, *Natural Gas Monthly Survey*, (July 2007). Online at http://www.iea.gov.

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where it occurs mostly in association with crude oil production. U.S. exports to Mexico primarily serve industries in the north. In all, there are 12 natural gas pipeline interconnections at the U.S-Mexico border, which add up to an import capacity of 3.4 billion cubic feet per day.[8] Interconnections representing about half of this capacity are connected to the isolated system of Pemex Gas (in the state of Sonora) and to other natural gas companies in northern Mexico (Sempra in Baja California and Gasoductos de Chihuahua in Chihuahua).

Completion of several pipeline projects in recent years has supported the increase in export volumes at U.S.-Mexican border points. Exports of about 96 billion cubic feet at the U.S.-Mexican border at Ogilby, California, on the North Baja Pipeline accounted for about 30 percent of U.S.-Mexico flows, the highest of any point of exit to Mexico. Deliveries over the Roma, Texas, border point on Kinder Morgan's Mier-Monterrey Pipeline were 20 billion cubic feet, representing 6 percent of total exports to Mexico. Construction of the Mier-Monterrey Pipeline was completed in March 2003. Deliveries on the Tennessee Gas Pipeline at Rio Bravo, Texas, increased 20 billion cubic feet to a total of 60 billion cubic feet, as flows continued a steep increase following the completion in 2003 of the pipeline's South Texas expansion project.

The average price of U.S. pipeline exports to Mexico during the year was $6.46 per thousand cubic feet ($6.46 per million Btu's), which was 17 percent lower than the average price in 2005.[9] The value of total trade with Mexico was $2.1 billion, a decrease of $282 million, or 11.9 percent, from the previous year.

Many industries are building facilities in the country in the aftermath of the passage of the North American Free Trade Agreement, allowing for greater industrial consumption.

Higher demand for natural gas in Mexico is occurring in several sectors. Mexico's demand for electricity, most of which is fueled by natural gas and petroleum products, rose by nearly 5 percent per year nationwide between 2004 and 2006. Residential and commercial users' requirements for natural gas continue to grow, resulting in increased pipeline infrastructure to serve these sectors. In addition, many industries are building facilities in the country in the aftermath of the passage of the North American Free Trade Agreement, allowing for greater industrial consumption.

In the near term, supplies are expected to increase significantly with the start of operations at the Costa Azul LNG project, near Ensenada, which is owned by Sempra Energy, Inc. Costa Azul LNG will have peak capacity of 1 billion cubic feet per day. While much of the regasified LNG will supply domestic customers in northwest Mexico, some natural gas also will likely be exported to California and/or Arizona. Additionally, Mexican authorities have initiated a tender for the construction of an LNG receiving terminal at the port of Manzanillo. The tender calls for the terminal to supply 500 million cubic feet per day of natural gas for 15 years, possibly expanding to 1.5 billion cubic feet per day. The government has targeted 2011 for the commencement of the plant's operations.

CONCLUSION

Pipeline imports from Canada declined. U.S. natural gas exports to Mexico rebounded after a steep decline in 2005 (which included a period of extremely high prices in the aftermath of Hurricanes Katrina and Rita).

NOTES

1. Because of delays in reporting, this article uses 2006 data. Nevertheless, the drivers and trends have application today—*Ed.* This article is a partial abridgement of part of a larger report that also includes an extensive analysis of liquefied natural gas (LNG) imports, Gaul, D. (2008). *U.S. natural gas imports and exports: 2006.* http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2008/ngimpexp/ngimpexp.pdf.
2. International Energy Agency. (2007, June). *Natural Gas Monthly,* http://www.iea.gov.
3. Canadian Association of Petroleum Producers, *Statistical Handbook.* http://www.capp.ca.
4. National Energy Board, "Short-term Canadian Natural Gas Deliverability," (October 2007), p. 19.
5. Energy Information Administration, Gas Transportation Information System, Natural Gas Pipeline Capacity Database.
6. See note 1, Table SR2, Summary of Natural Gas Imports, 2005–2006.
7. Energy Information Administration (2007, November). *Mexico Country Analysis Brief*. Washington, DC.: Author.
8. Energy Information Administration, Gas Transportation Information System, Natural Gas Pipeline Capacity Database.
9. The heat content of natural gas exported to Mexico is 1,000 Btu's per cubic foot. Thus, the price of gas exported per million Btu's is the same as the price per thousand cubic feet.

Does Analyst Guidance Show Anticipated Winning Sectors in Exploration Services?

Robert E. Willett

It does not, taking guidance as a whole. Opinions from the analysts are all over the map when you try to go past the most global level—oil and gas services as a whole. There is enough varying opinion on each company that one cannot gain any real idea of which subsector[1] (**Exhibit 1**) will gain the most in the near future if, indeed, any one subsector will.

SUBSECTORS MOVING TOGETHER OR SEPARATELY?

They may logically move as a group (e.g., the more drilling, the more cementation or drill bits required).

Conversely, factors that would make the segments move independently could include, for example, technical innovation or the customer itself beginning to provide more of a particular service, dimming the outlook for the subsector that contained that service. Weighted averages of the scores assigned to ratings by respected analysts who Fidelity shows on its Web site would indicate that there indeed may be a difference:[2]

Weighted Average Score by Sector

Drillers	2.46
Other direct services	2.70
Services	2.52
Technical	3.09
Overall	2.58

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In this case, "1" is a perfect score, and the closer to 1 the better. Thus, by this logic, the drillers should do the best and the techies the worst.

But these are statistics and thus subject to statistical analysis. I ran tests on the significance of the difference between each of the averages and the overall mean, where appropriate, and other tests (for smaller samples) to determine whether it was possible that those averages differed from each other significantly. In no case was there any significant difference: there was a very low probability that any of the subsectors' average scores differed from each other by anything more than random chance.

This analysis would indicate that the analysts as a group see no breakout for any of the subsectors. But let me not be misinterpreted: individually, the analysts indeed do have very strong opinions on the futures of various individual stocks: this is their job.

Note also here that Value Line's respected "timeliness" rating for these stocks is listed separately. Even for those listed "1" (most timely) in Value Line, said to be a list of sure winners, as a group there was no agreement about this ranking by the other analysts in the sum of their analyses. There was a slight but in no way significant agreement.

NOTES

1. These subsectors should be fairly clear when looking at Exhibit 1. "Other direct services" is composed of tasks that must be done to make a well complete in addition to drilling (e.g., wire-line services). "Services" generally means those specialties that may be used in drilling a well but are available to the *drilling process* and not independent of it. "Technical" concerns companies that offer particularly high-tech applications.
2. Calculated by assigning a score to each level of favorable recommendation (e.g., Buy = 1, Outperform = 2, and so on). Thus, the lower the average score, the more favorably the group is viewed by analysts as being the most likely to reap the benefits of anticipated exploration and development.

 DOI 10.1002/gas /

Exhibit 1. Analysis Data for Various Oil and Gas Exploration Services Stocks

	ValueLine			Fidelity Research Summary (1)				
	Price % Change 2010–12		Timeliness	Buy	Outperform (2)	Neutral (3)	Underperform (4)	Sell (5)
	Low	High						
DRILLERS								
Transocean	55	130	1	2	1	3		
Diamond Offshore	–15	30	2	1	1	5		
Helmerich & Payne	25	105	2	1	3	3		
ENSCO	50	125	3	1	2	1		1
Nabors	45	135	3	1	4			
Noble	35	105	3		3	3		
Rowan	50	125	3	1	2	1	1	
Subtotal				7	14	16	1	1
OTHER DIRECT SVCS								
Schlumberger	25	70	2	1		1	2	
BJ Svcs	110	200	3		2	1		
Global Inds.	15	75	4		1	2		
Subtotal				1	3	4	2	
SERVICES								
CARBO Ceramics	45	100	4	1		2		
Baker Hughes	40	115	2	2		3	1	
Cameron Int'l	25	85	2			NONE		
Nat'l Oilwell Varco	60	140	1	1	1	3		
Weatherford	15	70	1			3		
Halliburton	45	120	2		3	3		
Helix	45	115	2			NONE		
Smith Int'l	55	125	2	1	1	3		
Tidewater	45	115	3		2	1		
RPC	30	135	4			2		
Subtotal				5	7	20	1	0
TECHNICAL SUPPORT								
Core Labs	0	125	2		1	1	1	
ION Geophysical	25	105	4			2	1	
Tetra	80	135	4			5		
Subtotal					1	8	2	0
				13	**25**	**48**	**6**	**1**

(1) Includes only analysts with a StarMine Accuracy Score greater than 80. The body of the table in this section consists of the number of analysts making the same call for the same company of May 6, 2008. For example, on that date, three analysts were neutral on Smith International.
(2) Includes Overweight, Favorable.
(3) Includes Hold, Sector Perform.
(4) Includes Underweight, Unfavorable.
(5) Includes Most Unfavorable.

Sources: http://eresearch.fidelity.com/eresearch/goto/evaluate/analystsOpinions.jhtml?, http://www.valueline.com/secure/vlispdf/stk1700/lookup.aspx?keyfld=industryname&keyword=Oilfield+Svcs%2fEquip.

Liquidity and Price Competition in the Atlantic LNG Trade

Chris Goncalves and Jessica Thompson

Recent rising fuel prices have supported a rise of resource nationalism in the Americas and Africa, indirectly fostering a greater interest in diversified sources of energy such as liquefied natural gas (LNG) and renewables. Enticed by escalating global oil prices and aiming to fortify domestic wealth and prosperity, producing nation leaders are increasingly inclined to expropriate the assets of and/or redefine commercial terms with foreign oil and gas companies operating on their soil. Such appropriation of producer rents often results in the weakening of productive capacity by discouraging investment.

Recent rising fuel prices have supported a rise of resource nationalism in the Americas and Africa.

This instability jeopardizes supply and compounds international commodity price pressure. This, combined with international climate change and greenhouse gas concerns, has fostered an international wave of interest in alternative sources of energy such as LNG and renewables. Even countries that have not experienced severe economic disruptions are increasingly aware of the importance of developing new policies to diversify energy resources.

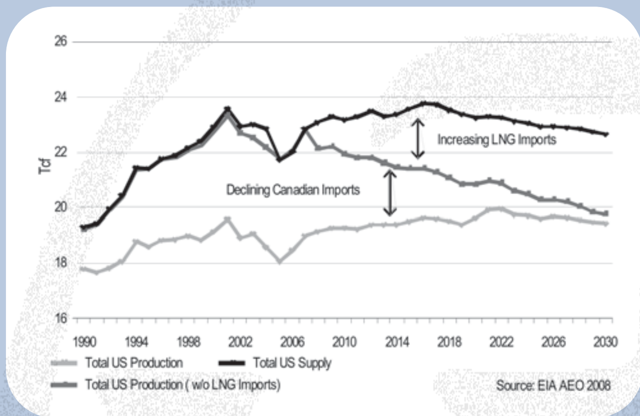
In the United States, the U.S. Energy Independence and Security Act of 2007 (EISA 2007) is a step in that direction. The Energy Information Administration (EIA) recently updated its 2008 Annual Energy Outlook (AEO 2008) to reflect the impact of EISA 2007 (**Exhibit 1**). Compared to prior EIA projections, the new report anticipates slower economic growth, reduced productivity, and higher crude and natural gas prices. It also assumes faster growth in nonhydro renewable energy resulting from state renewable portfolio standards. The result is an overall decline in the share of primary energy represented by coal and hydrocarbons from 85 percent in 2006 to 80 percent by 2030 and gas demand that is relatively flat—increasing slightly through 2016 and then declining slightly through 2030. On the supply side, the EIA expects U.S. conventional gas production to decline and be replaced by a doubling of new production from shale gas. With U.S. supply and demand both relatively constant, steeply declining Canadian pipeline imports are projected to create new market space for imported LNG.

The AEO 2008 projects quite moderate natural gas price expectations (**Exhibit 2**): the futures market is pricing gas much higher (with the United Kingdom outstripping the United States). One possible reason for this differential is that AEO 2008 stops short of accounting for the high likelihood that state and federal greenhouse gas legislative initiatives will be enacted over the near to medium term, eliminating more coal-fired generation in favor of cleaner natural gas and renewables.

Chris Goncalves and **Jessica Thompson** are with Navigant Consulting, Inc. The opinions expressed in this article are those of the authors and do not necessarily represent the views of Navigant.

DOI 10.1002/gas / © 2008 Wiley Periodicals, Inc.

Exhibit 1. Total U.S. Natural Gas Supply Including Imports Through 2030



INCREASING COMPETITION ENTERING LNG MARKET

Due to the difficulties of siting and building LNG terminals on the U.S. West Coast, U.S. demand for LNG as a diversified energy source will be concentrated among existing and new terminals along the eastern seaboard and Gulf Coast, putting increased pressure on Atlantic Basin supplies (**Exhibit 3**).

Currently, Europe dominates the Atlantic LNG trade, with 12 regasification terminals that offer approximately 10.7 billion cubic feet a day of import capacity. In 2006, however, only 5.5 billion cubic feet a day were imported, implying a regasification load factor of approximately 51 percent. Six new terminals that are under construction in Europe will bring 6.8 billion cubic feet a day online by 2018, for a total LNG import capacity of about 17.5 billion cubic feet a day (**Exhibit 4**).

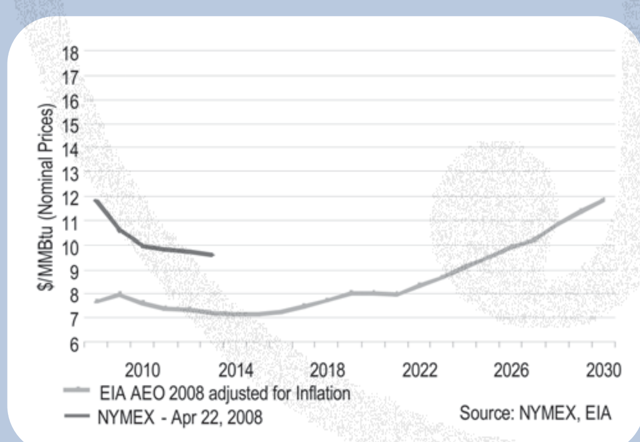
U.S. LNG import capacity is currently over one-third below that of Europe, with six existing terminals offering a total capacity of 6.3 billion cubic feet a day. However, six large new terminals are currently under construction and will bring total U.S. import capacity to 19.2 billion cubic feet a day by 2016, surpassing Europe by 1.7 billion cubic feet a day.

Further compounding the demand pressure on Atlantic Basin supply, South America will enter the LNG markets later this year as regional consumer nations pursue supply solutions to unreliable gas production among their neighbors. There are four new regasification terminals now under construction in Chile and Brazil, and they should add 1.3 billion cubic feet a day by the end of 2009. Further, several additional terminals being planned in Brazil, Uruguay, and Argentina could potentially double that capacity by 2015. In total, the new terminals under construction around the Atlantic Basin will increase the basin's total regasification capacity to 38.0 billion cubic feet a day by 2018.

South America will enter the LNG markets later this year as regional consumer nations pursue supply solutions to unreliable gas production among their neighbors.

This capacity will be only partially utilized, however, as comparatively little new liquefaction capacity is coming online. Just 11.2 billion cubic feet a day of new liquefaction capacity is now under construction or in permitting around the Atlantic (including Atlantic-dedicated terminals in the Middle East). This will increase total liquefaction capacity to 25.4 billion cubic feet a day by 2018. Compared to regasification capacity, this level of total LNG supply or export capacity (assuming its full utilization) implies that

Exhibit 2. U.S. Natural Gas Price Comparison, 2008–2030



  / DOI 10.1002/gas

regasification load factors will gradually climb to 67 percent by 2018.

Continued low regasification utilization may be appropriate, as Atlantic gas and LNG demand is highly seasonal. For example, Europe's summer trough demand is about 60 percent lower than peak demand. The region has limited storage resources and little can be done to mitigate this seasonality besides increasing LNG and pipeline import volumes.

By the same token, Europe's deep summer troughs yield excess LNG supply capacity that can be released to the Americas. The trend to divert flows to the United States during summer months will become more pronounced as liquidity increases in the Atlantic. With storage capacity at almost 20 percent of annual demand (versus 4 percent in the United Kingdom), the United States is able to absorb summer or shoulder-month LNG into storage, to mitigate winter price spikes.

South American gas consumers may also be able to benefit from counterseasonal purchase opportunities, as Southern Hemisphere hydro generation falls and winter demand peaks during the Northern Hemisphere summer.

Supplier trading decisions will be driven by liquefaction netbacks that reflect cross-Atlantic gas and LNG pricing and shipping differentials. As supply becomes more liquid in the Atlantic Basin, suppliers are becoming more aggressive in their efforts to capture seasonal trading margins. For instance, last winter, U.K. National Balancing Point (NBP) gas prices traded on average at $2.75 a million Btu's above U.S. Henry Hub gas prices, whereas price differentials were inverted in the summer of 2007—with U.S. prices trading at $1.51 a million Btu's higher than the United Kingdom's NBP, on average.

These recent seasonal commodity price differentials far outweigh current shipping differentials and will thus drive trading decisions. For example, North African LNG exports are much closer to Europe, with the U.S. and South American shipping prices almost double. From Algeria, it is approximately $0.58 a million Btu's cheaper to send LNG to the United Kingdom than to the United States. From Nigeria, this differential is currently only about $0.32 a million Btu's. From Trinidad, it is $0.25 a million Btu's cheaper to send gas to the United States than to the United Kingdom.

Shipping differentials are not currently great enough to overcome pricing differences during peak seasonal months, and so commodity prices are driving trade. Last December and January, for example, U.S. LNG import volumes ran at less than half the prior-year levels due to strong demand pull and prices in Europe. However, as LNG supply and import capacity increase liquidity, the Atlantic commodity price spreads should begin to tighten to reflect a mix of seasonal demand patterns and international shipping differentials.

Exhibit 3. Atlantic LNG Liquefaction-Regasification Capacity Balance (Bcf/d)

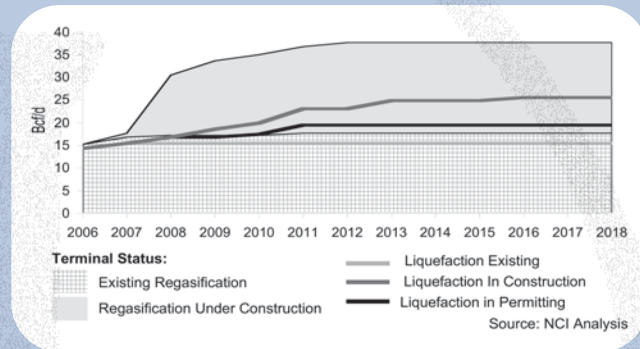
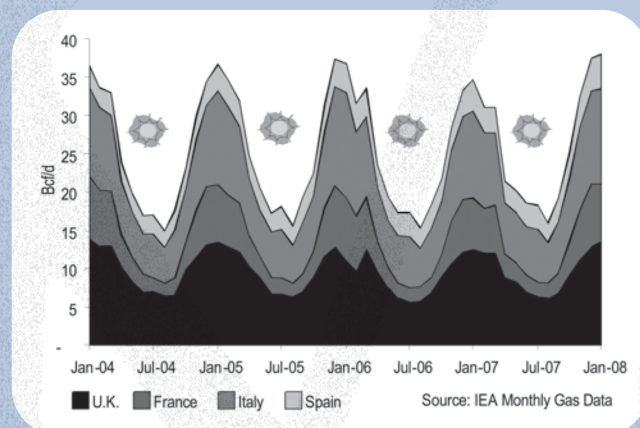


Exhibit 4. European Gas Demand (Bcf/d)



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Maybe the Fuel of Choice—Again

James J. Hoecker

Rick Smead, a Navigant director whose words appear in this publication semimonthly, recently observed that regulation of interstate natural gas markets has achieved such a level of stability in the last 15 years that "it's often difficult to pick a regulatory issue to write about." I agree. To toil toward resolution of the endless issues in electric restructuring is to be envious of this success. Yet while natural gas markets have achieved a liquidity and efficiency that ensures its economical delivery, the supply of and demand for this fuel remain caught in a familiar cycle.

The profile of today's natural gas industry seems like déjà vu all over again. Natural gas is once again becoming the darling of electric generators and those who think strategically about how to curb greenhouse gas emissions in the power and transportation sectors without sacrificing electric reliability. That is not to say that combusting this fossil fuel is emissions-free. Nor is it to argue that natural gas will displace coal as the nation's principal base-load power supplier.

Our domestic conventional gas resources are declining, giving rise to new supply-and-demand pressures. For the first time in a generation, some contend that valuable natural gas supplies should be allocated primarily to domestic heating, cooking, and air conditioning needs. Moreover, with prices per million Btu's moving north of $10 and little hope of a retreat to the $5 level that looked extraordinary only a short time ago, natural gas—like most forms of energy—is no longer inexpensive by most pocketbook definitions.

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ENERGY DÉJÀ VU

Of course, this should sound familiar if you have been paying attention. Demand for natural gas for boiler usage surged after passage of the Clean Air Act in 1967. The response that followed in the 1970s was a critical shortage of supply, accompanied (not coincidentally) by regional and national wellhead price regulation. With prices driven down to mere pennies per thousand cubic feet, exploration and production ground to a virtual halt. The conventional wisdom of the time was that domestic gas reserves were virtually exhausted, leading to the now-legendary Fuel Use Act, which forbade the use of natural gas in most industrial boiler-fuel applications.

Once again, the worm turned. Price decontrol under the Natural Gas Policy Act of 1978 reconstituted our domestic supply picture by the mid-1980s, while the advent of the combustion turbine and competitive power producers led to the development of gas-fired electric generation far in excess of its competitors in the 1990s. Most experts predicted a 30-trillion-cubic-foot domestic gas market. With growing competition in wholesale electric markets and growing numbers of natural gas–fueled transportation fleets, the place of natural gas in the national fuel portfolio seemed secure.

The turn of the century nevertheless brought the California energy crisis, the Enron debacle and a skepticism toward energy commodity trading, a recognition that conventional domestic gas reserves were in decline, and continued energy de-

  / DOI 10.1002/gas

mand growth. Gas prices began to leapfrog higher. Public utilities consequently began planning another generation of baseload coal facilities, and many gas-fired generators were relegated to operating as peaking units.

NATURAL GAS BACK ON TOP

Again, the fortunes of natural gas as the fuel of choice have turned positive. This is principally attributable, on one hand, to supply-side developments and, on the other, to widely anticipated changes in laws governing carbon emissions, particularly from electric generation.

There are numerous supply-side developments. Potential imports of liquefied natural gas (LNG) represent a significant boost to domestic gas availability, although it remains to be seen if U.S. markets will be price-competitive with Europe and Asia. In addition, producers are now aggressively developing very deep reserves offshore and unconventional supplies onshore. Shale formations in East Texas (Barnett Shale) and western Arkansas (Fayetteville Shale) are touted as long-lived reserves shale formations that are expected to brighten the domestic gas outlook. At current market prices, the cost of developing these resources ($5–$7) is easily justified. Finally, major producers and pipeline companies may at long last be getting serious about constructing a means to transport the 35 trillion cubic feet of natural gas long trapped in Alaska without pipeline access to the markets in the Lower 48 states. However, such a massive project will take years to authorize and construct.

Nothing has resurrected natural gas's prospects quite like the readily apparent political push to curb greenhouse gas emissions. Among fossil fuels capable of shouldering an increasing load of the electric power and transportation sectors, natural gas emits substantially less carbon than the alternatives. In fact, natural gas represents "the single best near-term solution" to U.S. energy challenges, states Denise Bode, executive director of the new American Clean Skies Foundation.

MEDIA IS THE MASSAGE (OR AT LEAST THE MASSEUR)

The Foundation, the brainchild of Aubrey McClendon, CEO of Chesapeake Energy, has launched a high-profile, high-gloss campaign to set forth "all the facts on clean energy" on behalf of natural gas and its wind and solar clean-energy "partners." The target of this print and electronic media onslaught is the coal industry. The messages appear calculated to persuade policymakers that increased production and use of natural gas, and gas produced from shale formations in particular, is integral to the half-century transition to the clean energy economy.

Intramural competition among fuels is characteristic of our domestic energy policy formation, but the Foundation carries it to a new level. The Foundation's approach is not unique: the Nuclear Energy Institute has been visibly promoting a renaissance in nuclear power, to good effect. In fact, climate change may make it necessary for legislators and regulators to abandon the pretext of fuel neutrality (and even fuel diversity) in public decision making. Climate change may also end the era of "least-cost" and short-term investment strategies that have left us with very tough choices in some areas. Appealing imagery can take the edge off some difficult decisions.

If the flashiness of the American Clean Skies Foundation is any indication, the public relations arena could rival the economic dictates of the energy markets themselves in exercising influence over the planning quietly taking place within the presidential campaigns during this election year. Washington apparatchiks are clearly watching. However, "we have a long history with the failure of the administrative fiat approach," states Rick Smead with respect to who, if anyone, should decide which is the fuel of choice. "Putting a price on carbon, but encouraging the steady growth in gas use [and supply] should probably be where public policy can help the most."

PR AND THE PUBLIC INTEREST

Conceding that point and acknowledging natural gas's inherent advantages in a highly emissions-conscious energy market, I wonder whether this new effort to influence the direction of public policy and perhaps to enlist public support for an energy source now priced at a premium will help crystallize and advance a transition to the clean energy economy or whether it will exacerbate the regional resource-based differences and factionalized policy debate that have always made it difficult to execute a truly national energy policy. Whatever its underlying agenda, McClendon's Clean Skies Initiative has to be a welcome stimulant to a discussion about our energy choices—and they are many and complex. The war of ideas is just cranking up, but natural gas is already riding high.

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Kansas Secretary Unilaterally Bans Coal Plants

Jonathan A. Lesser

Last fall, Secretary Roderick Bremby of the Kansas Department of Health and Environment denied an application for an air permit by Sunflower Electric in connection with the company's plan to build two 700-megawatt coal plants. In rejecting the application, Bremby cited the plants' projected emissions of carbon dioxide (CO_2)—even though no state or federal law regulates CO_2. Bremby said, "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."

Bremby cited the plants' projected emissions of carbon dioxide (CO_2)—even though no state or federal law regulates CO_2.

In March, the Kansas Legislature overturned Bremby's decision, but Governor Kathleen Sebelius vetoed the legislation. In April, the Kansas House of Representatives passed a new version of this legislation, which it hopes will either meet with the governor's approval or garner enough votes to override her veto. As I write this, the new bill has yet to be signed or vetoed.

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SHAKY LEGAL AUTHORITY, EVEN WORSE ECONOMIC REASONING

Bremby's authority to deny the air permit supposedly emerges from the Kansas Air Quality Act, which defines air pollution so broadly as to include just about everything under the sun.[1] Additionally, even if the U.S. Supreme Court's decision in *Massachusetts v. EPA* defines CO_2 as a pollutant,[2] there is a cavernous difference between stating that CO_2 is a pollutant and summarily banning new coal plants (or shutting down existing ones).

There is a cavernous difference between stating that CO_2 is a pollutant and summarily banning new coal plants.

Bremby's decision has legal implications,[3] but the economic implications are of more immediate concern, because environmentalists (and perhaps some renewable energy developers) are likely salivating at the prospect of expanding the Kansas precedent into a ban on new coal plants everywhere in the United States. Why stop with coal plants? In fact, to avoid the whiff of selective enforcement, Bremby's banning of coal plants would have to be extended to all major sources of CO_2 and other greenhouse gases: automobiles;

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oil production and refining; aircraft manufacturing; chemicals; agriculture; and, well, just about everything.[4]

Bremby's banning of coal plants would have to be extended to automobiles; oil production and refining; aircraft manufacturing; chemicals; agriculture; and, well, just about everything.

In the 2007 annual report of "Kansas, Inc." (a government agency that performs analysis and promotes economic growth in that state), Governor Sebelius said, "To ensure the promise of opportunity for future generations, we must build an environment that encourages business creation and growth."[5] Some might ask how reducing the supply of electricity and raising its price will help accomplish the governor's goal. Of course, the answer is that development of renewable generation will create untold thousands of new jobs. Sure.

ECONOMIC IMPACT STUDIES CAN BE VERY MISLEADING

Numerous studies tout the economic benefits of renewable resource development. For example, a paper published in June 2007 by the National Renewable Energy Laboratory (NREL) estimated that building about 55,000 megawatts of new wind turbines in the western states by 2015 would create over 270,000 "jobs" during construction and over 480,000 jobs over a 20-year operation period.[6] Wow! It almost sounds too good to be true—and it is.

It almost sounds too good to be true—and it is.

To understand why this is a false promise, a little background about typical economic impact analysis studies will help. Job impacts are divided into three categories: direct, indirect, and induced.[7] The *direct* impacts of building a generating resource include all of the people who actually bolt the thing together, plus everybody who helps build the component parts. For example, building a wind farm requires construction workers to pour concrete foundations, crane operators to erect the turbines, workers to string the power lines and build a substation, and so forth. It also requires workers (likely located somewhere else) to build the turbines, manufacture cement, fabricate copper wire, and engage in other like activities.

The *indirect* job impacts arise because all of the industries that the wind farm developer purchases equipment and materials from also purchase equipment and materials. The cement plant, for example, requires equipment, raw materials, and electricity. The wind turbine manufacturer buys steel, ball bearings, gears, and generators. In this way, the process continues. Finally, *induced* impacts arise from the wages spent by all of those employees, who are also consumers.

Most economic impact studies determine employment impacts by looking at the total expenditures needed and tracing those expenditures through the local, state, or even national economy. Thus, if a proposed wind farm will cost $100 million to build, that $100 million injection is allocated among all of the different input industries (including construction) to determine the overall economic impacts on the economy.[8]

Spending $100 billion to build new wind turbines may indeed create thousands of jobs, but so might spending that money on new coal and nuclear plants, or even spaceships.

Now, there is nothing at all wrong with economic impact analysis: such studies can shed light on the overall impacts of different public policies.[9] But these economic paeans to renewable resources typically fail to provide some crucial additional information. First, most studies fail to provide benchmarks for comparison. Spending $100 billion to build new wind turbines may indeed create thousands of jobs, but so might spending that money on new coal and nuclear plants, or even spaceships. Second, many studies, including the NREL study, fail to consider where the money comes from for these expenditures.

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In the case of building new renewable resources (wind or otherwise) to meet mandatory renewable portfolio standards (RPSs), the money will come from ratepayers. To the extent renewable resources are more expensive than conventional generation supplies, electric rates paid by consumers will increase. As their rates increase, ratepayers will have fewer dollars to spend. Thus, manufacturers—especially electric-intensive ones—will be less inclined to invest in new production facilities if the cost of electricity is too high, and they may raise the price of their products. The same is true of commercial firms. Retail consumers will pay higher prices for electricity, and they will also pay more for all goods and services that use electricity as an input. In essence, an RPS that mandates development that would not otherwise take place is a tax. And taxes do not create jobs—they reduce jobs.

An RPS that mandates development that would not otherwise take place is a tax. And taxes do not create jobs.

Critics may argue that such taxes are "worth the price" if we are to achieve broader environmental and social goals, such as reducing dependence on foreign oil or reducing CO_2 emissions in Kansas. But nobody should be under the illusion that banning coal plants—or any other type of fossil fuel generation—and replacing them with renewable resources will provide economic manna from heaven. Renewables have risks, too, and costs that must be considered.

What are Kansans going to do when their power goes out, they find the courage to pull back the curtain on the renewable wizard's promises, and they discover that behind it is . . . nothing?

For example, what happens when the wind does not blow? Texans found out on February 26, 2008, when all but about 50 megawatts of the state's 1,200 megawatts of wind turbines stopped turning just as electric demand rose. ERCOT (the operator of the Texas system) found itself in an emergency situation and turned to fossil-fuel generation to keep the lights on.

What are Kansans going to do when their power goes out, they find the courage to pull back the curtain on the renewable wizard's promises, and they discover that behind it is . . . nothing? Move to Texas?

NOTES

1. State of Kansas Air Quality Statutes, Chapter 65.—PUBLIC HEALTH, Article 30.—AIR QUALITY CONTROL. Section 65-3002 states the following:

   Definitions. As used in this act, unless the context clearly requires otherwise:

   (a) "Air contaminant" means dust, fumes, smoke, other particulate matter, vapor, gas, odorous substances, or any combination thereof, but not including water vapor or steam condensate.

   (b) "Air contamination" means the presence in the outdoor atmosphere of one or more air contaminants.

   (c) "Air pollution" means the presence in the outdoor atmosphere of one or more air contaminants in such quantities and duration as is, or tends significantly to be, injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or property, or would contribute to the formation of regional haze.

2. *Massachusetts v. Environmental Protection Agency,* Slip Op. No. 05–1120.
3. For example, the decision smacks of "selective enforcement." If construction of new coal plants can be banned, why not ban purchases of cars, lawn mowers, and barbeques? Why not ban construction of new gas-fired generating plants, too?
4. The average individual emits about one-third of a ton of CO_2 per year. Because the population of Kansas is about 2.8 million, Kansans are emitting almost one million tons of CO_2 each year just by breathing.
5. *Kansas, Inc., 2007 Annual Report,* available at http://www.kansasinc.org/pubs/AR/AR2007.pdf.
6. Tegan, S., Milligan, M., & Goldberg, M. (2007, June). Economic development impacts of wind power: A comparative analysis of impacts within the Western Governors' Association states, Conference Paper NREL/CP-500-41808, p. 11 (Figure 4). Available at: http://www.nrel.gov/wind/pdfs/41808.pdf.
7. Another issue concerns jobs versus job-years. Most studies, including the NREL study, estimate job-years. In other words, they estimate full-time equivalent (FTE) jobs created, not actual jobs.
8. The more local the area studied is, the smaller the estimated economic impacts will be. The reason is that more expenditures "leak out" of the local economy.
9. The author of this column has performed his share of these analyses. For example, see (1994). Estimating the economic impacts of geothermal resource development. *Geothermics,* 23(1), 43–59. Readers who would like a copy of this article can e-mail me.