THE NATURAL GAS CRISIS – IMPLICATIONS FOR ENERGY EFFICIENCY AND DEMAND RESPONSE COST-EFFECTIVENESS ANALYSIS

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OVERVIEW

This paper discusses recent trends in the gas industry and their impacts on electric markets. Uncertainty in gas prices was cited as a major issue at a recent conference for the coal industry.[1] Issues discussed in this paper include:

- The need to inject natural gas into storage in the summer resulted in high prices in 2003 and may continue to be a concern in future years.
- Natural gas has largely been a North American market, but recent trends indicate that North American production may not be able to meet growing gas demands; as a result, liquefied natural gas (LNG) could be the key to long-term gas and power prices.
- Higher and possibly more volatile gas prices and related high power prices will impact the economics of energy efficiency (EE) and demand response (DR) programs.
- EE and DR programs can impact price volatility and provide benefits by reducing costs of hedging against high prices; however, current benefit-cost frameworks need to be modified to capture these benefits.

NATURAL GAS CRISIS AND OUTLOOK FOR GAS

Recent Trends in Natural Gas Markets

In 2003, gas prices were characterized as "a crisis." The crisis had its origins in several places; the fallout from the Enron debacle had left a shaken industry and supply and demand were out of balance. When these imbalances were assessed in the context of the amount of gas in storage and the need to replenish storage levels, gas prices climbed.

Gas prices at the wellhead were below \$3/Mcf until late 2002 (see Figure 1). Wellhead prices increased in the fall of 2002 in a normal seasonal pattern, but then continued to increase. Natural gas prices averaged over \$6/Mcf for the month of March 2003 and spiked to \$15/Mcf on some days. In the off-season in fall 2003, wellhead gas prices are down to what seems a comparatively low \$4.50/MMBtu.

Residential and commercial prices also increased this year. Xcel Energy in Colorado announced a 73% increase in gas rates due to the expansion of the Kern River pipeline that brought regional gas prices more in line with national prices. Across the country, the expected increase is not as great, but retail prices are expected to be up substantially this winter across most regions.

[1] Blankinship, Steve, Natural Gas Uncertainty Prevailing Concern at Coal-Gen '03, Power Engineering, Sep, 2003, p. 9.

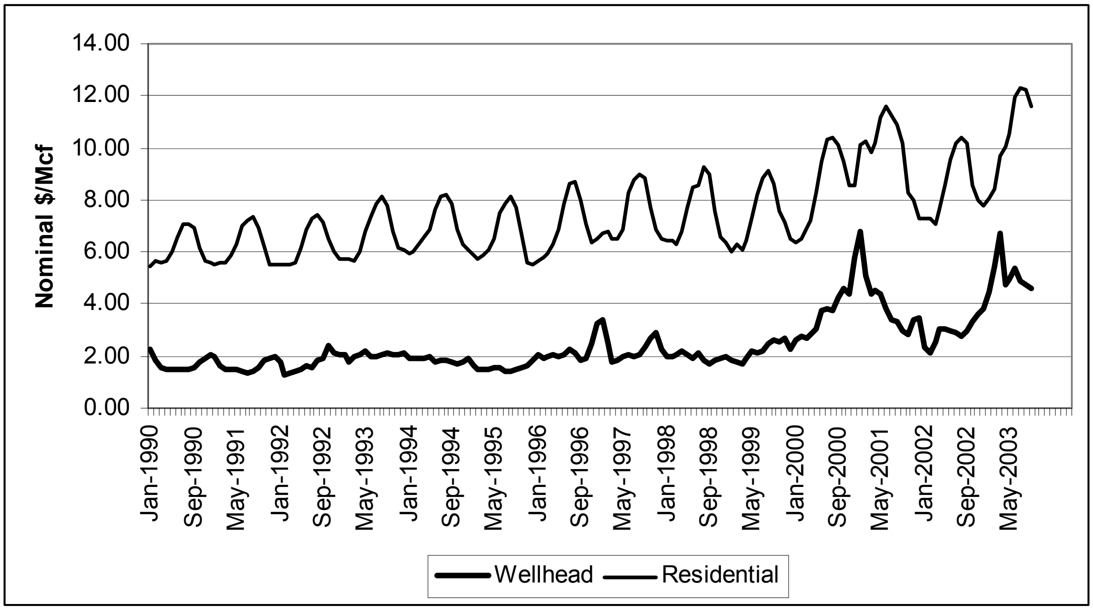

Figure 1. Gas Price Source: EIA

The concern in the early summer was whether enough gas would be injected into storage in order to have sufficient gas in storage at the start of the winter heating season (see Figure 2). A cold winter and low production reduced storage levels far below last year and below the range of the previous five years. This matter received considerable public attention. Federal Reserve chairman Alan Greenspan[2 3] took up the call and testified before congress regarding natural gas and the amount of gas in storage.

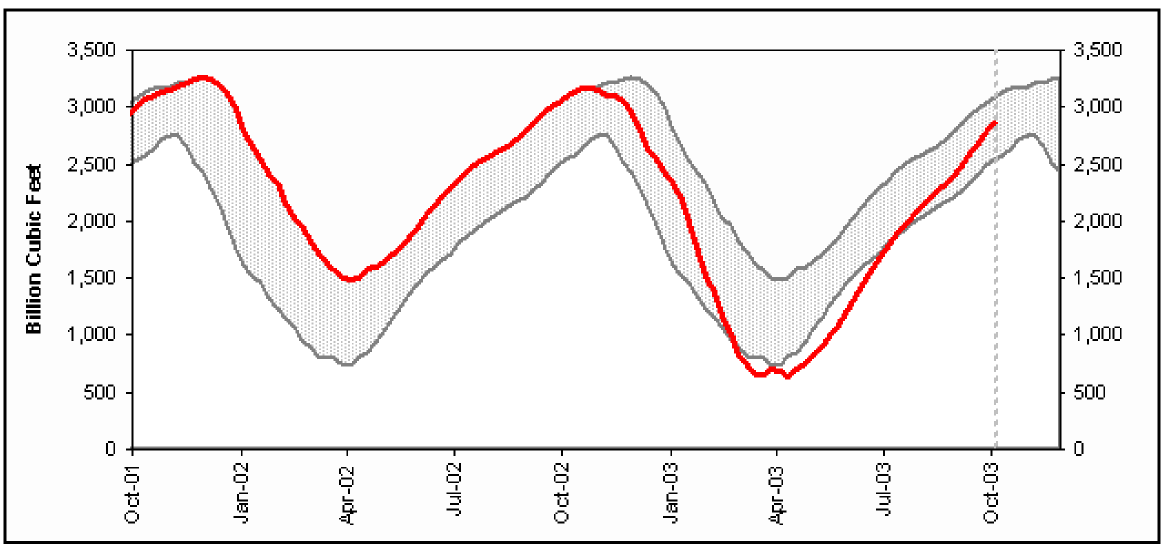

Figure 2. Natural Gas in Storage Source: EIA, Data for Week Ending Oct 3, 2003

Fortunately, and perhaps due to the public attention given to the issue, the gas industry aggressively injected gas into storage. At the time that this is being written in early October, it now appears that gas

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[2] Greenspan, Alan, Testimony of Chairman Alan Greenspan on Natural Gas Supply and Demand Issues before the Committee on Energy and Commerce, U.S. House of Representatives, Federal Reserve Board, June 10, 2003.

[3] Greenspan, Alan, Testimony of Chairman Alan Greenspan on Natural Gas Supply before the Committee on Energy and Natural Resources, U.S. Senate, Federal Reserve Board, July 10, 2003.

storage levels will be at about 3.1 trillion cubic feet (Tcf) at the start of the winter heating season. This level is within the range of what is considered adequate.

While the industry has been able to come through in 2003, it is important to realize that storage injection is likely to be an issue every summer. Current levels of gas production will not provide the margin that has existed in the past to ensure that storage can be refilled at prices similar to those seen in the past few years.

US Gas Demand and Supply

Gas production in the United States has been relatively flat whereas demand has increased steadily (see Figure 3). Consumption in 2002 was about 64.6 billion cubic feet per day (bcf/d) and production was about 52.1 bcf/d[4], a difference of 12.5 bcf/d in 2002. This difference value of 12.5 bcf/d is a number that will be re-examined later in this article. The difference is primarily pipeline imports from Canada, but also includes small amounts of LNG imports and the net difference between storage injections and withdrawals. The difference has been increasing over the years and is expected to continue to increase.

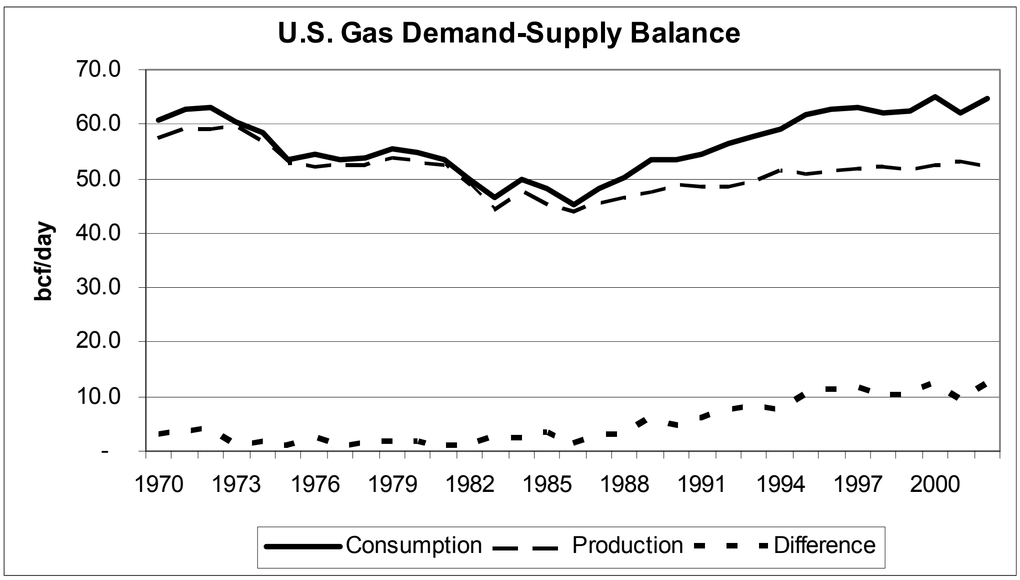

Figure 3. U.S. Gas Demand-Supply Balance Source: BP Statistical Review of World Energy 2003

US Gas Drilling and Production Prospects

One obvious solution to the gas crisis would be increased production. The near-term prospects for additional North American gas production do not look good. Before production can increase significantly, more gas wells will have to be drilled. Normally when prices go up, the industry responds by drilling more wells. Low gas prices in much of 2001 and 2002 resulted in fewer new wells drilled in 2002. However, significantly higher prices in 2003 have not resulted in major increases in gas drilling. Figure 4 shows that overall drilling has been below 2001 levels in the United States for most of 2003.

[4] BP Statistical Review of World Energy 2003, June, 2003.

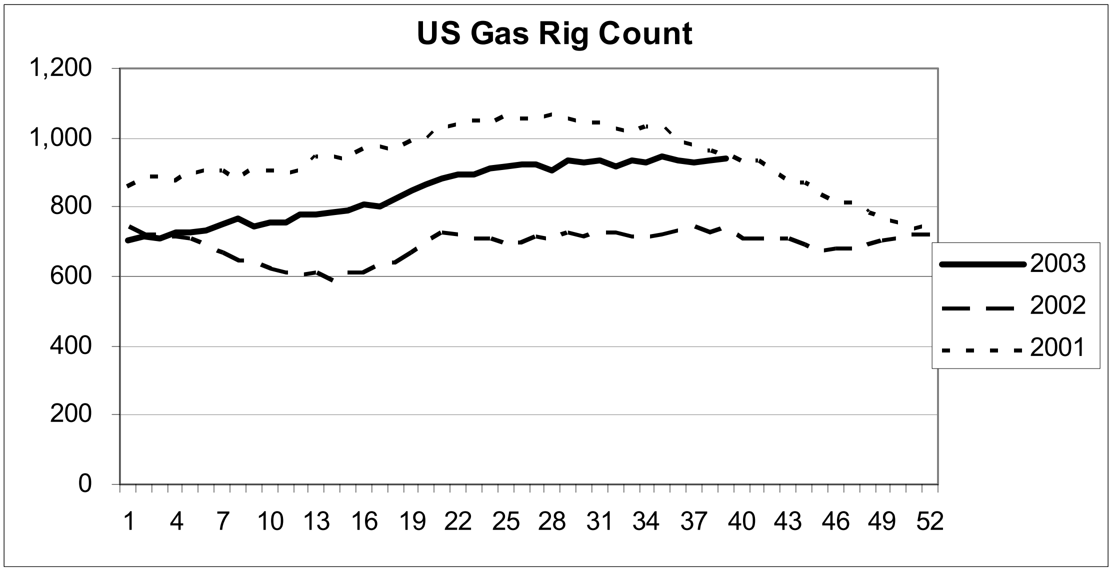

Figure 4. U.S. Gas Rig Count Source Baker-Hughes

Drilling has also been low in 2003 in key basins (see Figure 5). The primary opportunities for increased gas production in the United States are in the Rocky Mountains and the Gulf of Mexico. In 2003, drilling was low in these areas due to environmental related restrictions and a lack of good opportunities. Opportunities for increased production from coal bed methane reserves in the Rocky Mountain and San Juan basins have been slowed by environmental reviews and restrictions because of associated saline water production. The government slowed leasing in these regions while environmental reviews were being conducted. Increased leasing has been undertaken recently, but some prime coal bed methane areas have leasing restrictions. Drilling in the Gulf of Mexico is not only below 2002 levels, but is below 2001 levels. Drilling in the Gulf of Mexico has been low reportedly because of comparatively few opportunities for new wells. Thus, the two key basins in the United States for additional gas production are not showing as much of an increase as the change in gas prices would imply. Without an increase in drilling, significant increases in gas production from these key regions cannot be expected.

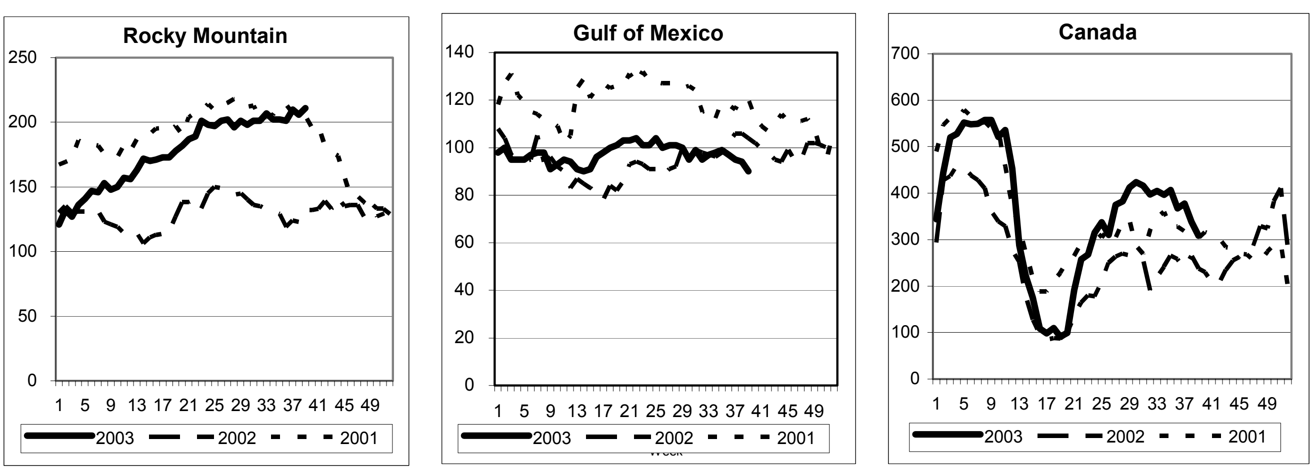

Figure 5. Drilling Rig Count in Key Regions Source: Baker-Hughes

Canadian Gas Production Prospects

The United States has come to rely on Canadian gas to make up the difference between demand and supply in the United States. Canadian imports accounted for 94.2% of U.S. imports in 2002. The United States had expected continued growth in Canadian production. Several pipelines were built or expanded in the 1990s to bring in Canadian gas, including the Alliance, Northern Boarder, and Viking pipelines.

Recently, however, a very significant change occurred in Canadian gas production. The primary source of Canadian gas is from the Western Canada Sedimentary Basin located in Alberta, Saskatchewan, and British Columbia. Production from western Canada has started to decline. Two recent, authoritative studies state that production from western Canada has peaked and entered a long-term decline.[5] [6] This represents a paradigm shift in North American gas markets. The U.S. can no longer count on Canadian gas production to meet ever growing needs for gas.

Figure 5 includes Canadian drilling rig count. Canadian drilling picked up somewhat in summer 2003, but is not greatly above 2001 levels. United States imports from Canada were down 9.6% in the first half of 2003, which contributed to the surge in gas prices.

Gas Well Production Decline

Another factor contributing to the tight supply situation is the high rate of decline in gas well production. U.S. gas well production declines 25% to 30% per year,[7] and this decline rate has been increasing in recently competed wells. New wells must be drilled and completed just to keep production level with previous years.

Long-Term Options for North American Gas Production – Artic Gas

The primary opportunities for increased long-term production in North America are in the MacKenzie Delta and in Northern Alaska. While there are already significant discoveries of gas in the artic regions, the timing of these supplies coming into the United States depends on building pipelines to deliver the gas to market.

An agreement to initiate work on a pipeline along the MacKenzie River was reached this year.[8] This pipeline will not be in service until 2008-2010. The MacKenzie River pipeline is proposed as 0.8 bcf/d, which is a small piece of the long-term needs of the United States and Canada.

A pipeline to Alaska is still being debated. Alaska currently produces some 8 bcf/d of natural gas, but it is re-injected to maintain oil production. If a pipeline is built to Alaska, it is not expected to enter service until roughly 2015. Even if Alaskan gas were the long-term answer, there is a long interval where additional gas is needed.

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[5] Alberta Energy and Utilities Board, Alberta's Reserves 2002 and Supply/Demand Outlook 2003-2012, Statistical Series 2003-98.

[6] National Energy Board, Canada's Energy Future, Scenarios for Supply and Demand to 2025.

[7] National Petroleum Council, Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy, Volume 1, Summary of Recommendations and Findings, Sep. 25, 2003, p. 39.

[8] Imperial Oil Resources, Funding Agreements Reached & Preliminary Information Package to be Submitted, Mackenzie Delta Producer Group Confirms, June 18, 2003.

Thus, the near-term natural gas picture is for continued tight markets. Production is currently having a difficult time matching demand. Only minor increases in production appear on the horizon due to modest drilling. Production will have difficulty keeping up with demand growth. Long-term prospects for major, new pipeline sources of gas to the United States are not great until Alaskan gas is brought in, if Alaskan gas is brought in.

ENTER LIQUIFIED NATURAL GAS

Existing LNG Terminals and Sources

Liquefied natural gas appears to be an increasingly important factor. The United States has had four LNG import and regasification terminals for many years. Some of these were shut down or operating at low levels. Now, all four are back open and operating. The fourth and largest existing LNG terminal, Cove Point, Maryland, reopened with its first shipment on July 23, 2003. A combination of the reopening of Cove Point, the completion of the third LNG liquefaction train in Trinidad and Tobago in May, and additional shipments from Nigeria are likely to result in LNG shipments tripling in 2003, from 0.7 bcf/d in January to over 2 bcf/d by December.

LNG is primarily a way of transporting natural gas from producing areas to consuming markets. LNG is feasible where large resources of gas are found in remote locations. If there is not an existing market for the gas or a pipeline cannot be built to deliver the gas to market, then LNG becomes an option if there are sufficient gas reserves. LNG requires a series of large investments that include exploration and development of the gas reserves, construction of a liquefaction "train," construction of specialized tankers, and a regasification plant. Total costs can range from $5 billion to $10 billion. It seems that the industry wants to see about 40 Tcf of reserves to justify the expenditure of building a liquefaction train. If there is more gas, then more trains can be built. With this large investment, LNG developers also generally want firm contracts for the LNG. Something of a spot market is developing, however.

Some people question the wisdom of becoming dependent on foreign suppliers of gas. They see the potential for the United States to become dependent on another cartel like OPEC or on unfriendly countries. While this is a concern, the North American gas supply situation does not give the U.S. much choice. The countries likely to supply gas to the United States are somewhat more diverse than the oil-suppliers and some are friendlier. It is important to have a wide range of countries supplying LNG to the United States, not only for political reasons, but also to avoid supply disruptions due to hurricanes, typhoons, fires, or equipment failures.

U.S. LNG imports are currently dominated by gas from Trinidad and Tobago, which are islands off the coast of Venezuela. Trinidad and Tobago accounted for about 77% of U.S. LNG imports in the first half of 2003. Large gas resources and proximity to the U.S. market have made LNG from Trinidad and Tobago one of the key ingredients in the U.S.'s LNG revival. Costs for LNG have declined dramatically in the last few years. Part of this cost decline is in the equipment and technology used to liquefy the gas. A significant part of the cost of LNG depends on the distance that LNG is transported. The proximity of Trinidad and Tobago to the U.S. gives the islands a price advantage over most of the competition and allows for lower cost gas to be supplied to the United States.

Trinidad and Tobago are projected to continue to dominate east coast supplies of gas. All four existing LNG terminals in the United States are on the east or gulf coasts. The existing terminals and their likely sources of supply are shown in Figure 6 below. The imports from Trinidad and Tobago are likely to be joined by imports from their neighbor, Venezuela. Norway's Statoil owns one-third of the Cove Point terminal and is currently constructing a production and export facility in the Barents Sea. African nations make up the rest of the east coast supply. Some east coast LNG will also come from Middle Eastern sources, particularly Qatar. Though new terminals have been proposed for the east or gulf coasts of the United States, Mexico or Canada, the major sources of LNG are not likely to change significantly unless major, new discoveries are made.

Terminal	Capacity Now (bcf/d)	Future Capacity (bcf/d)	Supply Source
Everett, MA	0.46	0.92	Trinidad Algeria
Cove Point, MD	0.75	1.00	Trinidad Norway Nigeria
Elba Island, GA	0.45	0.81	Trinidad Venezuela Equatorial Guinea
Lake Charles, LA	0.91	1.20	Trinidad Egypt Venezuela
Total Capacity	**2.57**	**3.93**	

Figure 6. Existing U.S. LNG Import Terminals Source: EIA, Gordon Shearer[9]

Future LNG Terminals and Supplies

Vastly expanded LNG imports are expected in the long term. Many new LNG terminals have applied for permits and approvals are starting to come in. Sempra Energy recently received approval for new LNG terminals in Louisiana and Baja California.

New terminals are proposed for the east, west and gulf coasts as well as Canada and Mexico. New terminals in eastern markets will be important. The first new terminals on the west coast or northern Mexico will also be added and will change markets there. More than a half-dozen LNG terminals have been proposed for California or northern Baja, Mexico. There were so many west-coast LNG terminal proposals that the California Energy Commission felt compelled to include three LNG terminals in its LNG scenario rather than simply one.[10] LNG import terminals serving California and Baja Mexico could have a major impact on the supply-demand balance in the west. Each terminal represents roughly 1 bcf/d of new supply while the current total pipeline capacity into California is 8.3 bcf/d. LNG would influence not only California markets but also upstream where the traditional sources of pipeline gas for California are located.

Adding West Coast LNG terminals opens up the United States to new sources of supply, but also world competition. Historically, the largest producers and consumers of LNG have been in the Pacific basin. International LNG consumption has been dominated by Japan, which received 50% of world LNG shipments in 2002 and has about 20 LNG import terminals. Indonesia was the largest exporter of LNG

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[9] Shearer, Gordon, US LNG Imports, If There Is a Will, Is There a Way, Opportunities and Obstacles for Algerian LNG, Potent Partners, Nov. 7, 2002

[10] California Energy Commission, Natural Gas Market Assessment, Report 100-03-006, August, 2003, p. 64.

in 2002, and Malaysia was the third largest. Likely source countries for West Coast LNG imports to the United States include:

Australia	Brunei
Indonesia	Oman
Russia (Sakhalin Island)	Qatar
Malaysia	Peru

Most supplies of LNG, particularly new supplies, involve the super-major oil and gas companies. The capital involved means that this is a game for the super-major players. Often the local, state-owned company is one of the partners, but the super-majors are also involved. The primary companies importing LNG into the United States include ExxonMobil, Royal/Dutch Shell, ChevronTexaco, ConocoPhillips, TotalElfFina, BG, and BP. Often these companies own or lease a portion of an LNG terminal and have LNG production facilities in one or more supplying countries.

It is important to realize that the first new LNG terminals will not be ready until 2007. There is a gap from now until 2007 that must be met by existing production, pipeline imports and existing LNG import terminals. It is also important to know that there will most likely be a long-term need for more LNG terminals and imports as North American gas production continues to decline and demand continues to grow. The United States will become increasingly dependent on imported gas. The U.S. gas market will enter an international era rather than the North American market that has been the case up until now.

Similar to the recent overbuilding in power plants and because of all the LNG terminals proposed, too many import terminals could be constructed. With all the terminals trying to be the "first" one online, there could be too many terminals in 2007 and 2008. And like power plants, the need for these terminals will likely be absorbed over time. However, over-construction could lead to soft markets. One advantage of a worldwide LNG market is that if one market is soft, the tankers can be re-directed to other, more attractive markets. This feature of LNG could moderate price volatility to a certain extent.

LNG as the Marginal Supply of Gas

Soon after 2007, LNG will become an even more significant source of gas supply to the United States. Each terminal represents about 1 bcf/d of gas, so five more LNG terminals would represent about 5 bcf/day of gas or 9 bcf/d total with the expanded, existing terminals. This compares to the current difference between U.S. demand and production of 12.5 bcf/d. LNG may become the marginal supply of gas to the United States. As the marginal supply, it may tend to set the price of natural gas. LNG suppliers would probably prefer to be price takers, particularly with gas prices over $4.50/MMBtu as they are now. By the time LNG becomes a significant source of supply, however, LNG may well be the price setter.

Thus, the price of LNG can provide an indication of where gas prices are headed in the long run. The wholesale price of LNG delivered to pipelines in the east coast of the United States generally ranges from $3.00/MMBtu to $3.50/MMBtu (west coast prices would be higher due to the longer transport distances). This indicates that natural gas prices would decrease from between $4.00/MMBtu and $6.00/MMBtu today to the $3.00/MMBtu to $3.50/MMBtu in the long run range if gas prices move down to the LNG price as the marginal source of supply. Costs for LNG have been decreasing in recent years and larger LNG facilities imply continued decreases. As a result, the price of natural gas in the United States could hold steady in the range of $3.00/MMBtu to $3.50/MMBtu or even decrease over time with LNG prices.

It is useful to have an indication of where gas prices are going, but it is also useful to know where gas prices are not going. In the long run, LNG as the marginal supplier of natural gas would tend to reduce natural gas prices from the current $4.00/MMBtu to $6.00/MMBtu range. It may be appropriate to include gas prices in the $4.00/MMBtu to $6.00/MMBtu range for 2004 through 2006 in benefit-cost studies and power price forecasts, but starting in 2007 gas prices may change. It also seems unlikely that gas prices will return to the $2.00/MMBtu to $3.00/MMBtu range that was experienced for much of the historical period.

This price projection is slightly lower than the CEC's Gas Forecast,[11] which projects gas prices to remain in the $4.00/MMBtu range delivered to generators (in real terms) from 2003 to 2013. This LNG–based gas price projection is also lower than those in the recent National Petroleum Council gas report, which projects gas prices to generally remain in the $4.00/MMBtu to $6.00/MMBtu range from now until 2015.[12]

Despite this scheme where gas prices are related to LNG prices, it is also likely that gas prices will continue to be volatile. Gas prices have been highly volatile over the recent historical period and will likely remain so. Certainly short-term weather and demand fluctuations could result in gas price swings.

Gas Prices a Determinant of Electric Prices

Gas price is one of the determinants of power prices and the gas component of power prices will follow the gas price path indicated above. Wholesale power prices should decrease in 2007 and 2008 as more LNG terminals are added and begin to influence the price of gas. Like gas prices, electric prices are likely to see continual volatility and price swings as short-term shortages or excesses occur.

IMPLICATIONS FOR BENEFIT-COST ANALYSES OF EE AND DR

Cost-benefit analyses of energy efficiency and demand response programs should include consideration of these long-term trends in gas and electric prices. Today's prices may reflect a cyclical shortage and not the long-term price trend that might occur if LNG attains its potential as a source of supply in gas markets.

Higher prices and increased price volatility are likely to increase the cost-effectiveness of EE and DR programs. Gas and power prices are significantly higher than they were as recently as last year. Though gas and power prices are projected to decrease somewhat from today's prices, they are still considerably higher than prices in the past.

Energy efficiency and demand response are also important parts of meeting future energy needs. The National Petroleum Council's recent study of natural gas identifies energy efficiency options as its first recommendation for achieving the nation's economic goals and meeting our aspirations for the environment at reasonable cost and for a secure energy supply. This study recommends "updating building codes and equipment standards…, promoting high-efficiency building materials and Energy Star appliances, encouraging energy control technology including 'smart' controls, and facilitating consumer responsiveness through efficient price signals."[13] This study points out that electric energy

[11] *Ibid*., p. iii.
[12] National Petroleum Council, Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy, Volume 1, Summary of Recommendations and Findings, Sep. 25, 2003, p. 15.
[13] National Petroleum Council, Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy, Volume 1, Summary of Recommendations and Findings, Sep. 25, 2003. p. 72.

efficiency and demand response programs also help the natural gas situation because they reduce the need to run peaking plants, which are usually gas-fired, and improve load factor, which can also reduce the demand for gas.

The value of avoided gas and electricity is one issue, but there are other issues that need to be addressed in benefit-cost analyses including the impact of programs on gas and electricity price volatility, amelioration of scarcity conditions, and market impacts such as the overall impact of reduced consumption on energy prices and the ability of changes in demand to curb price spikes and address concerns about market power on the supply side. These issues argue for adjustments to the framework of energy efficiency and demand response cost-benefit analysis. For example, one focus of DR programs is to avoid spikes in market prices. Traditional benefit-cost analyses may not be able to account for this hedging benefit. Also, reducing market power has been mentioned as a benefit of DR programs, yet this is a hard to quantify benefit.

Work is ongoing in a number of venues to update benefit-cost frameworks[14 15]. This section focuses on benefits and the discussion is divided into two parts. The first set of benefits is benefits accruing to the sponsoring utility. The second set of benefits is referred to as extended benefits and occurs in the market or because of the market. These benefits included in this new benefit-cost framework are identified in Figure 7 and discussed below.

Utility Benefits

1. ***Deferred or eliminated generation or T&D capital expenditures***
2. ***Real options value for addressing unlikely events***
3. ***ISO or other payments***

Extended or Market-Wide Benefits

4. ***Market price benefits to non-participants (collateral/transfer benefits)***
5. ***Hedging benefits***
6. ***Reliability benefits***
7. ***Overcoming market barriers***
8. ***Incentive to develop and adopt technology***
9. ***Increased portfolio diversity***
10. ***Provide operating reserves***
11. ***Other ancillary services benefits***
12. ***Reduce market power***

Figure 7. Potential Benefits in the New Benefit-cost Framework

Before discussing benefits, it should be noted that benefit-cost analysis can use forward looking revenues and costs rather than a retrospective analysis. A forward looking framework better accounts for the impact of program start-up and the spread of costs over an appropriate level of impact. A retrospective analysis that uses actual impact may or may not reflect the impact that would occur on a

[14] California PUC and the California Energy Commission have implemented a proceeding to update the evaluation framework for EE and new frameworks are being developed for DR.

[15] See also Chris Ann Dickerson et al., "Energy Efficiency as a Financial Hedge: An Alternative Valuation Methodology and Analytic Context for Energy Efficiency Programs" in the proceedings of International Energy Program Evaluation Conference, Seattle, WA, p 991; 2003.

typical basis or the impact that the program was designed and budgeted to achieve. The use of actual data may also cover too short of a period to amortize start up costs for a program. Forward-looking analysis can reflect the benefits of demand-side programs due to changes in planned supply-side additions. These changes in planned additions are often the key to exceeding benefit-cost ratio thresholds, whether the changes are in power plants, T&D, or market prices that reflect these changes.

Utility Benefits

1. Deferred or eliminated generation or T&D capital expenditures
Traditionally, the prime benefit of EE or DR programs has been the deferral or elimination of capital investments associated with new generating units. Where appropriate, deferral of generation may still be one of the most important benefits of EE and DR programs. In addition, EE and DR related improvements in load factor can lead to changes in the type of unit, from combustion turbine to combined cycle, and benefits from spreading generation costs over more MWH.

In the new industry structure, some utilities auctioned off their generation and are now only retail service providers with transmission and distribution (T&D) assets. These utilities' benefits may come from avoided T&D investments. Given the difficulties in siting new lines and substations, deferral of T&D facilities may not only be a benefit, but also a necessity.

In addition to impacts on capital expenditures, EE and DR programs can also have transmission and distribution system benefits if sited in congested areas. One of the key areas of interest for DR is in southwest Connecticut where there is a chronic shortage of generation and transmission capacity. EE and DR can also increase substation transfer capability in certain situations. These transmission and distribution changes can have a significant impact on locational marginal prices (LMP).

2. Real options value
This benefit refers to using DR as a hedge against low-probability, high-consequence events. Unlikely events are often related to equipment malfunctions or extreme weather. Such events have a low probability of occurrence, but can require expensive approaches to avoid service interruptions. An example from a utility involved using liquid nitrogen to cool an overloaded transformer at a substation.

Unlikely events do happen, however low the probability of their occurrence. DR provides a utility with more options for dealing with these types of events. Because these types of events may not occur every year, benefits may not accrue every year. Real options are suggested as a way to quantify the unique nature of these types of benefits.

3. ISO or other payments
The most obvious benefits of EE or DR programs are payments from ISOs or other agencies. Traditionally, utilities instituted EE and DR programs for their own benefit. Now, programs may be developed to address perceived needs by ISOs or other agencies, and the agencies may make payments for the program. The payments may not cover the full costs of the program, however, and only be part of the overall benefits.

Extended or Market-Wide Benefits

4. Market price benefits to non-participants (collateral/transfer benefits)
One of the main reasons to develop EE and DR programs in the new industry structure is to reduce market prices. Power prices under the new market structure have shown a pronounced propensity to

spike. These price spikes have reached extremely high prices, and market caps have been instituted in some regions to limit these price spikes. Because of this propensity to spike, a small change in demand can result in a large change in prices. The bid curve for a delivery point in the ISO-New England region on August 14, 2002 shows that a 5% reduction in demand through DR programs in ISO-New England would have halved electricity prices (from $1,000/MWH to $500/MWH).[16]

Reducing peak period prices and price spikes benefits all of the customers in that market, in this case the spot market for electricity in New England.

5. Hedging benefits
Hedging benefits result from reducing the contingency expenses due to reduced market prices and reduced market price volatility due to EE and DR programs. Hedging benefits could result from the ability to avoid purchasing hedging instruments or from lower costs for those financial instruments.

6. Reliability benefits
EE and DR programs can increase the reliability of the system and reduce the likelihood of outages. The Northeast blackout of August 14, 2003 made this a more visible and important benefit. This benefit can be calculated from the change in loss of load probability and estimates of customer outage costs. DR may also be able to reduce the number of under-frequency and under voltage events, which can lead to cost savings on both utility and customer equipment.

7. Overcoming market barriers
Market barriers to customers adopting DR programs can be addressed as more programs are implemented. Each program can make for easier implementation of future programs.

8. Incentive to develop and adopt technology
Similar to the market barrier issue, more programs could lead to better technology for these types of programs. There aren't a lot of programs with real time pricing, for example, so there isn't a lot of equipment capable of automatic response to price signals. More programs would result in more equipment. More programs and more equipment would lead to more impact.

9. Increased portfolio diversity
DR provides another independent option for meeting load. Most of the generation that was built in recent years has been gas-fired and a very high proportion of peaking generation is gas-fired. This means, as the first part of this paper indicated, that power prices are often highly related to natural gas prices. DR is independent of gas prices, however. Including more DR will help reduce the dependence of power prices on gas prices. DR provides diversity to the portfolio in both type of capacity and type of "fuel."

10. Provide operating reserves
DR can provide ancillary services benefits by providing operating or spinning reserves. If DR programs can be dispatched quickly enough, they can substitute a portion of spinning reserves carried on the system. In this manner, DR can not only increase reliability but also reduce costs if DR provides spinning reserves and other ancillary benefits at lower cost than other types of resources. The Northeast blackout on August 14 indicated the need for spinning reserves and controllable load. If systems in the Northeast had more DR, they might have had a better chance of preventing a cascading blackout.

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[16] See Townsley Consulting Group "*ISO-NE 2002 Demand Response Program Evaluation*" prepared for the ISO-NE, April, 2003.

11. Other ancillary services benefits
EE and DR may also provide other ancillary services benefits and receive payment for these benefits. Non-spinning or contingency reserves are an obvious target for DR and depend on the amount of time allowed for load curtailment. Voltage and frequency control have been mentioned as another ancillary service that DR may be able to provide.

12. Reduce market power
Reducing market power is widely advocated as a reason for more DR programs. Particularly in the wake of the California energy crisis and the concern for market power there, demand response was desired as something that could be done to counter the power of the small number of plant owners. Because DR programs are often independent of the generators, DR helps reduce the concentration of ownership in the market.

Identifying these benefits is only part of the task. Quantifying benefits is another challenging effort, and new efforts in this area are being undertaken.

CONCLUSION

In conclusion, this paper has shown how recent trends in gas prices are influencing markets for electricity, and the importance that LNG could have in these markets. This paper also discussed the way in which these changes might impact the benefits of EE and DR programs. These trends in gas and power prices and a new benefit-cost framework that takes these trends into account might alter the economic outlook for EE and DR programs.

Given the changes in the structure of the electricity industry, assessing benefits in cost-effectiveness analyses needs to include both benefits that arise to a utility or distribution company, and benefits that are market-wide and accrue to all energy consumers in a region. These regional benefits can extend well beyond a specific utility's service territory. Including only the utility benefits might result in programs not being implemented due to low benefit/cost ratios calculated from a utility perspective. When extended benefits in the market are considered, however, benefit-cost ratios can increase by an order of magnitude.[17] This indicates the importance of the market benefits and the importance of the new, market based framework for benefit-cost analysis of EE and DR programs.

[17] Work done by the authors and available on request.