Energy Economics Research

at the Bureau of Economic Geology

Bureau of Economic Geology, Scott W. Tinker, Director
Jackson School of Geosciences, The University of Texas at Austin

THE ROLE OF LNG IN NORTH AMERICAN NATURAL GAS SUPPLY AND DEMAND

CEE
CENTER FOR ENERGY ECONOMICS

Michelle Michot Foss, Ph.D.
Chief Energy Economist and CEE Head
1650 Highway 6, Suite 300
Sugar Land, Texas 77478
Tel 281-313-9763 Fax 281-340-3482
energyecon@beg.utexas.edu
www.beg.utexas.edu/energyecon/lng

September 2004

Table of Contents

List of Tables and Figures

Tables

Figures

The Role of LNG in North American Natural Gas Supply and Demand[1]

Executive Summary

The dynamic elements that constitute the "energy mix" of North America are open to conjecture, debate and discussion. But amid the uncertainties, one conclusion appears inarguable: North America has always exhibited a strong appetite for natural gas, and the demand for this relatively clean burning natural resource will grow substantially in the years ahead. How, when and where the United States, Canada and Mexico respond to these inevitable demands for more natural gas will exert a powerful influence on everything from household purchasing power to national economic health.

In an energy environment dominated by crude oil, it may be tempting to overlook or minimize the potential consequences of policies that could impact the supply and demand of natural gas. But the facts warrant a different perspective. In a very real sense, natural gas represents a powerful "wild card" in the energy mix of North America that can help reduce energy price volatility and soften the attendant economic shocks. Played intelligently, this natural gas "card" can help assuage the continent's thirst for ever-dwindling (and ever more expensive) supplies of crude

---

[1] This publication was undertaken by the *Center for Energy Economics (CEE)* as the Institute for Energy, Law & Enterprise, University of Houston Law Center, through a research consortium ***Commercial Frameworks for LNG in North America.*** Sponsors of the consortium are BG LNG Services, BP Americas - Global LNG, Cheniere Energy, ChevronTexaco International Gas Group, ConocoPhillips Worldwide LNG, Dominion Energy, El Paso Energy, ExxonMobil Gas & Power Marketing Company, Freeport LNG, Sempra Energy Global Enterprises, Shell Gas & Power and Tractebel LNG North America/Distrigas of Massachusetts. The U.S. Department of Energy-Office of Fossil Energy provides critical support and coordination with other federal agencies and commissions. The Ministry of Energy and Industry, Trinidad & Tobago participates as an observer. Members of the technical advisory committee include American Bureau of Shipping (ABS), CH-IV International, Det Norske Veritas, Lloyd's Register, Project Technical Liaison Associates (PTL), and Society of International Gas Tanker and Terminal Operators (SIGTTO). This report was prepared by Dr. Michelle Michot Foss, Executive Director, CEE; Mr. Fisoye Delano, Senior Researcher; and Dr. Gürcan Gülen, Research Associate; with assistance from Mr. Dmitry Volkov, graduate student research assistant. The views expressed in this paper are those of the authors and not necessarily those of the University of Houston. Peer reviews were provided by LNG consortium advisors, UH faculty and other outside experts from both the U.S. and international organizations.

oil; played improperly, and natural gas policy miscues could deal substantial setbacks to the three economies of North America for years to come.

It is a conclusion of this report that easily accessible supplies of natural gas are readily available to answer pending increases in demand for natural gas in North America. The "catch" is that many of these supplies (either from remote areas of North America, or from other foreign countries) must be transported as liquefied natural gas, or LNG. By investing in an infrastructure capable of handling larger quantities of LNG, the countries of North America can reduce the "gaps" (and the resultant economic upheavals) that occur when natural gas supplies fail to immediately meet the demands and needs of industries and consumers.

Natural gas is hardly unique as a hydrocarbon for its three primary applications:

- For home heating and other direct energy uses;
- For electric power generation; and
- As a feedstock for a vast array of basic, intermediate and final materials and products.

But in the hierarchy of energy resources, natural gas stands alone as a premium, environmentally preferred fuel and feedstock. These characteristics underscore why natural gas will always remain a highly attractive fuel source – but they are not the sole reasons why demand continues to outstrip supply in the United States (which is both the largest producer and consumer of natural gas in North America[2].) Three primary forces have contributed to the protracted supply-demand imbalance in natural gas.

From the early 1970s to late 1980s, falling natural gas prices encouraged natural gas use but discouraged investment in exploration and production (E&P).

---

[2] Throughout this paper, the term "North America" is used to refer to the three major contiguous countries of Canada, the United States and Mexico, which are also the three signatory nations under the North American Free Trade Agreement (NAFTA) and that share a continental natural gas marketplace through linked natural gas pipeline grids (and a common electric power marketplace through linked electricity grids). The islands of Greenland, Saint-Pierre and Miquelon and Bermuda are not included in this analysis or definition.

- Divergent and conflicting environmental priorities have seen policymakers promote natural gas use while discouraging resource development by restricting access to public lands.
- Advancements in exploration and production technology may have improved success in discovering new supplies – but they have also increased production and hastened depletion among existing natural gas fields.

Similar forces have undermined the vibrancy and viability of natural gas interests in Canada. To further cloud the natural gas picture in North America, Mexico's E&P efforts have failed to keep pace with that country's steadily expanding economy – which is increasingly turning to natural gas to fuel its ongoing development. From the perspective of the United States, the last thing North America needs is another large net importer of natural gas – something that Mexico risks becoming in the years ahead.

Potential sources of new natural gas exist throughout North America, but the law of diminishing returns applies to a finite resource and suggests that each incremental field will prove increasingly more difficult (and more expensive) to identify and develop. Some of the most alluring prospects are remote and pose unique challenges: from fields in the far northern territory of Canada and Alaska to the deepest waters offshore the United States and Mexico. While the physical hurdles to new development are substantial, they are equaled or surpassed by other obstructions. Mexico, for example, will need policy and regulatory reforms before it can properly exploit its extensive natural gas resource base. New laws barring development on wide swaths of land are now on the books in the United States and Canada, and any move to open public lands to exploration is typically challenged early and often in the courts.

A bright side to natural gas in North America is found in the mutuality of interests and the high degree of cooperation that characterizes relations among the three countries. The United States, Canada and Mexico have long engaged in active cross-border pipeline trade of natural gas, and the three countries share information and conduct regular bilateral and trilateral discussions on natural gas market development and policy and regulatory issues and initiatives.[3] The United States relies on Canada as a key supplier, and Mexico purchases an increasing amount of natural gas from the United States. The three NAFTA members know each other well – and each has a vested interest in any initiative to reduce or eliminate the volatility in the North American natural gas marketplace.

If natural gas is the "wild card" in the total energy picture of North America, then liquefied natural gas (LNG) could well be the ace waiting to be played. LNG offers Canada, the United States and Mexico the chance to supplement their domestic production with relatively low-cost natural gas purchased from a diverse range of countries. The LNG infrastructure is already in place in North America, with existing LNG import terminals operating in the United States providing critical incremental natural gas supplies for peak seasonal use. The global LNG industry is increasingly competitive, transparent, efficient and flexible, and new LNG import facilities that are under development, planned or proposed in each of the three countries of North America will undoubtedly add impetus to these trends.

Even the most conservative forecasts call for Canada, the United States and Mexico to allocate new and larger sums of dollars and pesos for domestic natural gas resource development in the years ahead. The nature of these investments will help dictate the growth rates of the three largest economies of North America. LNG deserves careful scrutiny, as do issues such as pipeline capacity, operating specifications, and defining the scope of environmental responsibility. And while the precise roadmap remains to be charted, the ultimate goal is clear: a North America where open, competitive and transparent markets contribute to supply-demand balances and long-term energy security.

---

[3] On December 9-10, 2003 the CEE hosted a workshop on North American natural gas market and policy issues attended by the North American Energy Working Group (led by U.S. Department of Energy, Natural Resources Canada and Secretaría de Energía de México) and other experts. The results of that meeting provided inputs to this document.

Introduction

The United States and Canada have used natural gas for well over one hundred years for a variety of industrial and commercial applications and to heat residential homes. Mexico and its less developed economy has always trailed its neighbors to the north in overall appetite for natural gas, but the country has long relied on natural gas as a feedstock for its petrochemical manufacturing facilities. For home heating and cooking, Mexico's residents overwhelmingly rely on liquid petroleum gas, or LPG (typically propane or a propane/butane mix; see Appendix 1 for a definition of LPG).

Despite its long history of use in North America, it was not until the 1970s that natural gas earned recognition throughout the continent as a fuel with intrinsic value and not simply as an interesting byproduct of oil production. In North America today, natural gas has matured into a "commodity" – a product where price is the only differentiation considered by potential purchasers. As a commodity, natural gas is openly traded on such leading exchanges as the New York Mercantile Exchange (NYMEX).

Physical sales of natural gas involve numerous pricing points, such as Henry Hub, located near Erath, Louisiana. At Henry Hub, like other market centers and hubs,[4] natural gas is aggregated by nine interstate and four intrastate pipelines. Collectively, these pipelines feed domestic natural gas production and natural gas supplies from the Lake Charles, Louisiana LNG receiving terminal to large customer markets in the Midwest, Northeast, Southeast, and Gulf Coast regions of the United States. With its multiple pipeline connections, key location in the Gulf Coast supply region and an average (DAILY) throughput of 1.8 billion cubic feet (Bcf), Henry Hub is the largest and most "liquid"[5] natural gas pricing point in the world. Compared

---

[4] See the U.S. Energy Information Administration's overview on market centers and hubs, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/market_hubs/mkthubsweb.html, and the important role they play.

[5] The term "liquid" is used in a financial, not physical, sense. "Liquidity" in commodity markets is a function of the number of market participants and associated financial commercial contracts and transactions. Typically, the more liquid a commodity market is, the more efficient that market works with respect to price discovery and transparency. See Appendix 3 for an explanation of liquidity.

against other markets across the globe, the North American natural gas market is recognized as the most competitive, transparent and integrated market operating under policy and regulatory oversight. (In many ways, the market organization and policy and regulatory approaches of Canada and the United States comprise a *de facto* "common market" for natural gas.)[6]

The challenges created by these market conditions include inherent difficulties in balancing gas supply and demand; difficulties in ensuring fairness in pricing; fiscal headaches associated with price risk and volatility; and trepidation in boardrooms and legislative offices about making long term investments to ensure future natural gas supplies and the infrastructure necessary to bring those supplies to the marketplace. Even the brightest piece of news – the strength of the natural gas resource base in Canada and the United States – comes with significant caveats. The good news is that reserves are sizeable; the cause for concern, of course, is that producing fields are maturing. Unlocking new natural gas resources will require considerable new investment in exploration and production (the "upstream"). Large sums will also be required to develop the new infrastructure to gather, process, and store and transport natural gas supplies (the "midstream") from ever more remote producing basins and deliver it to markets where natural gas is needed. Each NAFTA member will face critical decisions in the near term as it decides unilaterally, bilaterally and trilaterally exactly what course to follow to employ natural gas to maximum effect.

This briefing paper is the third in a series that describes the liquefied natural gas industry – its technology, markets, safety, security, environmental considerations and the increasingly important role that LNG may play (and perhaps "must" play) in the nation's energy future. It deals with natural gas supply and demand balances in North America, particularly for the contiguous United States, and the potential role for LNG in meeting supply requirements. The first paper, *Introduction to LNG*, informs the reader about LNG and touches on many of the topics related to the LNG

---

[6] For a detailed treatment of North American natural gas markets, policy and history of restructuring, refer to *North American Energy Integration*, CEE, 1998, www.beg.utexas.edu/energyecon.

industry. The second paper, *LNG Safety and Security*, assesses the safety and security aspects of LNG operations. This third paper, *The Role of LNG in North American Natural Gas Supply and Demand*, provides an in-depth analysis of why more LNG will be needed to meet U.S. energy demand. All three papers, plus additional information, will be included in a complete fact book, *Guide to LNG in North America.* For a quick review of main LNG facts, please see Appendix 1, *LNG Frequently Asked Questions*. Apart from the LNG research effort, for the past two years the IELE team at the University of Houston also has engaged in an independent review of North American natural gas market developments and outlooks. This work, as reflected in this briefing paper, parallels that of the National Petroleum Council's natural gas supply study. Many of the findings are similar. For more information on the NPC study effort, the reader can refer to www.npc.org.[7]

The North American Energy Picture

The general energy picture for North America is summarized in Table 1. While the United States is both the largest producer and consumer of total energy on the continent, it consumes more than it produces. This negative net primary energy balance makes the United States the continent's only net importer of energy. Canada and Mexico are net exporters – with almost all of their energy trade directed toward feeding U.S. demand.

Table 1. Primary Energy Supply and Demand in North America, 2001 (quadrillion Btu, British thermal units)[8]

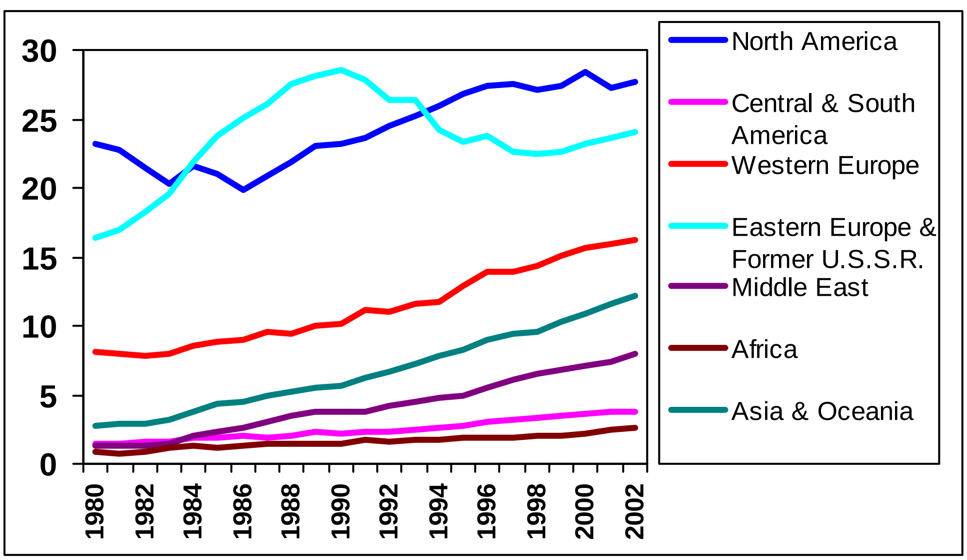
	U.S.	Canada	Mexico
Total primary energy production	71.57	18.20	9.59
Of which natural gas (%)	20.23 (28.3%)	6.74 (37.0%)	1.38 (14.4%)
Total primary energy consumption	97.05	12.51	6.00
Of which natural gas (%)	22.87 (23.6%)	2.98 (23.8%)	1.46 (24.3%)
Total net primary energy balance (production-consumption)	-25.48	5.69	3.59
Net natural gas balance	-2.64	3.76	-0.08
Source: U.S. Energy Information Administration (U.S. EIA)			

[7] National Petroleum Council, *Balancing Natural Gas Policy - Fueling the Demands of a Growing Economy*, Volume I- Summary of Findings and Recommendations, September 2003, www.npc.org.
[8] Primary energy constitutes all energy consumed by end users including fuels such as petroleum, natural gas and coal but excluding the secondary production of electricity from primary fuels.

Canada is the largest exporter of energy in North America, sending both crude oil and natural gas to the United States. Indeed, when exports of electricity are considered, Canada is the largest single energy supplier to the United States. Mexico's energy exports consist mainly of crude oil, with the United States serving as Mexico's major customer since Mexico initiated international oil sales in the 1930s.

Natural gas plays a significant role in North America's primary energy consumption, accounting for roughly 24 percent of the total 115.6 quadrillion Btu of primary energy used during 2001 (Table 1). Altogether, North America has remained one of the largest and fastest growing natural gas markets in the world (Figure 1). Natural gas trade is vigorous among the continent's three countries. As noted in Table 1 above, the United States does not produce as much natural gas as it uses. The "gap" between U.S. production and consumption of natural gas is largely filled by Canada. Canada is a vital participant in U.S. natural gas supply, helping to balance not only the U.S. market but also the North American continental market.

Figure 1. Worldwide Natural Gas Consumption, Quad Btu

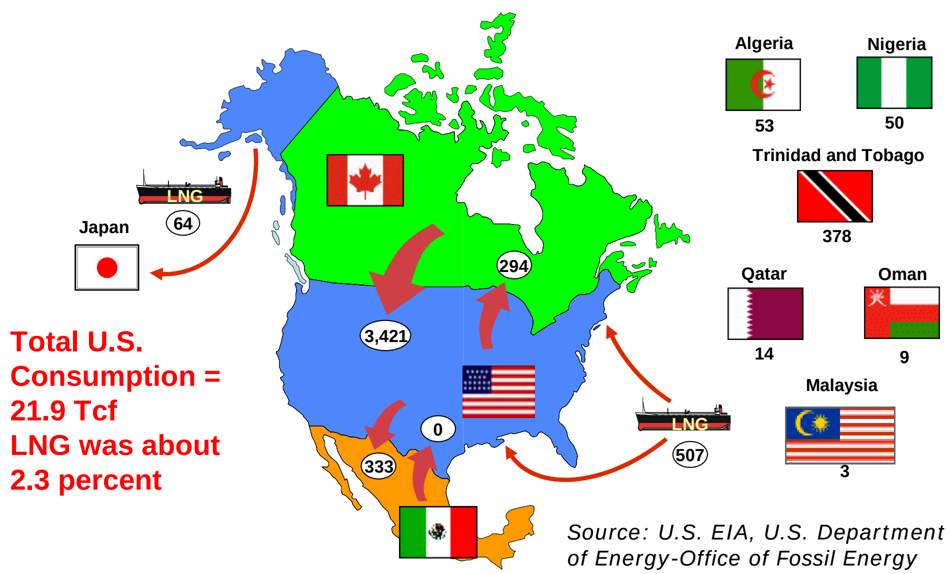


Source: U.S. EIA

Figure 2 illustrates, in volumetric terms, North American natural gas trade flows. The United States imported about 3.4 trillion cubic feet (Tcf) of natural gas via pipeline from Canada in 2003, roughly 15 percent of total U.S. natural gas supply.

The United States imports a small but increasing amount of natural gas from a diverse array of countries in the form of LNG, about 507 billion cubic feet (Bcf) in 2003 or 2.3 percent of the total natural gas supply. On the export side of the ledger, the U.S. pipes natural gas to Mexico (about 333 Bcf during 2003) and engages in small amounts of pipeline export trade along the Canadian border (about 294 Bcf during 2003). The U.S. also exported 64 Bcf to Japan via LNG. U.S. exports of natural gas are very small when compared to domestic production and imports, but even these quantities are important for maintaining regional balances, especially in northern Mexico. Note that while Mexico is a net importer of natural gas today, it previously was a net exporter – and could, with the right policies for upstream investment – regain that title in the future.

Figure 2. North American Natural Gas and LNG Trade, Bcf, 2003



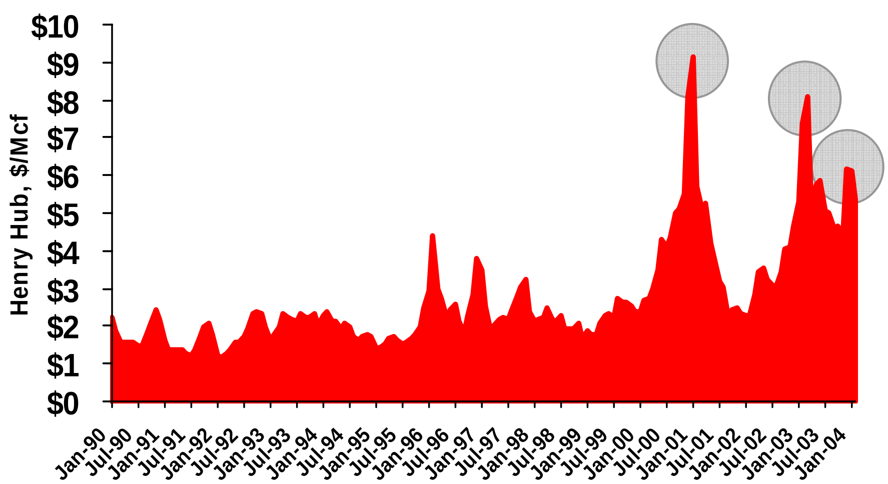
Understanding Natural Gas Price Trends: A Primer

To the consuming public, price is the most visible barometer to assess natural gas market conditions. But a wider perspective is required to properly assess the supply, demand and prices of North America's natural gas markets. Today's prices are a reflection of both past and present conditions in the industry as well as a "macro" snapshot of the present-day natural gas picture, including overall economic performance and weather patterns (which exert a substantial influence on natural gas use). The primer that follows is designed to help identify the drivers for natural gas supply-demand balances in recent years – and to extrapolate what current prices and historical trends may indicate for the years ahead. Because the United States dominates the North American natural gas market, and thus impacts and interacts with natural gas market conditions and prices in both Canada and Mexico, this primer focuses on short term and long term trends in U.S. natural gas prices.

Figure 3 below illustrates that since January 2000, the United States has experienced three extraordinary price spikes for natural gas. The first occurred during the winter of 2000-2001 and followed several years of strong economic growth and greater than normal, weather-related demand. These conditions effectively "masked" the true demand for both winter and summer needs: undercutting the true volumes needed for industrial power generation and winter heating, while overemphasizing the baseline demand for natural gas-fired power generation for peak summer cooling. A strong consensus has emerged among regulators, independent analysts, industry representatives and consumer groups that supply-demand imbalances were the primary factors behind the winter 2000-2001 price spike.

Figure 3. Natural Gas Prices – Henry Hub Cash Market Trading[9]

Source: Natural Gas Week



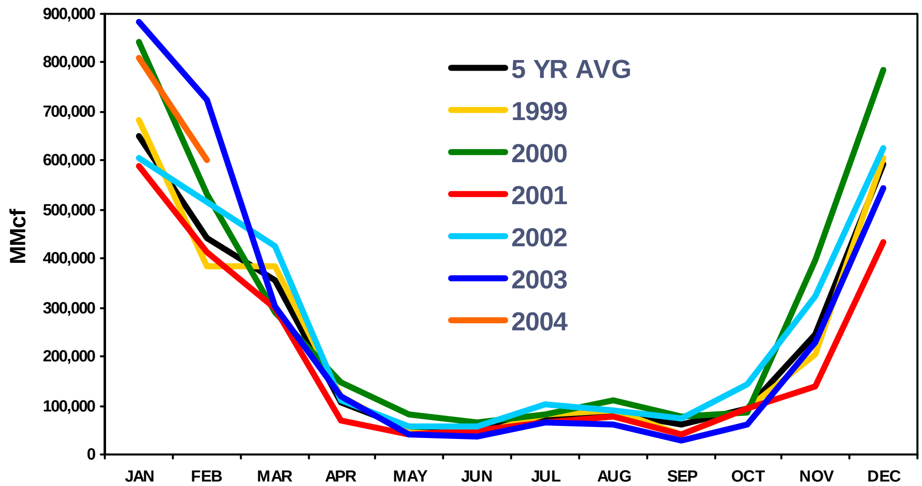
[9] The cash or spot market price for Henry Hub is almost identical to the "near month" of the Henry Hub futures contract at the New York Mercantile Exchange or NYMEX. Neither price incorporates basis differentials for other locations, such as the disputed California border. Prices are expressed in dollars per thousand cubic feet or Mcf of natural gas.

The second price spike occurred during the winter heating season of 2002-2003 and the third during the winter heating season of 2003-2004. These spikes share two characteristics: both emerged during winter seasons that were considered "normal" when compared to weather patterns in recent years; and both occurred during slack U.S. economic conditions. In both February 2003 and December 2003, market fundamentals – including the imbalance between market demand deliveries of natural gas from both storage and pipelines, along with isolated below-normal winter weather events and other factors – proved to be the major drivers for price movements during these periods.

In any one year the supply-demand balance for natural gas includes storage withdrawals. The United States maintains a large inventory of natural gas supplies in underground storage facilities and in the form of LNG at LNG peaking and satellite storage locations.[10] Storage facilitates production from natural gas wells in off-peak consumption months and balances the market during periods of strong demand, such as winter heating seasons. Annual storage withdrawal activity is generally compared to historical norms, such as a five-year average. Natural gas prices tend to be higher during seasons and years when storage withdrawal activity exceeds historical norms. This was the case during the three price spikes experienced between 2000 and 2004. Figure 4 shows the large withdrawals made during the periods in question.

[10] See CEE, Introduction to LNG, www.beg.utexas.edu/energyecon/lng for information on U.S. LNG storage facilities.

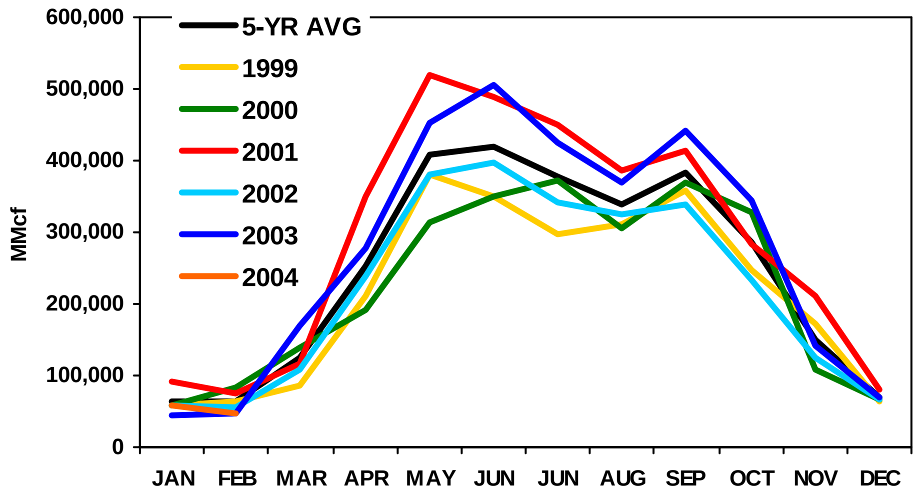
Figure 4. Withdrawals from U.S. Underground Natural Gas Storage Facilities, million cubic feet (MMcf)



Source: U.S. EIA

Natural gas withdrawn from storage must be replaced in time for the next heating season by injecting gas back into storage facilities (Figure 5). Typically, these "refills" are completed during summer months when natural gas prices tend to decline. But if demand for natural gas remains high during the summer – due to peak electrical generation during "heat waves", or because of strong economic growth – then gas prices may remain high and less gas will be injected into storage facilities. If demand for natural gas slackens below anticipated levels (due to an economic recession, such as the one that followed the events of September 11, 2001), prices can be expected to decline and gas supplies that would otherwise be consumed are injected back into storage. A simple equation emerges that strongly correlates short-term natural gas prices with the amount of gas injected each summer (relative to historic norms) along with the demand for gas in the winter season to follow (again, relative to historical norms).

Figure 5. Injections into U.S. Underground Natural Gas Storage Facilities, MMcf

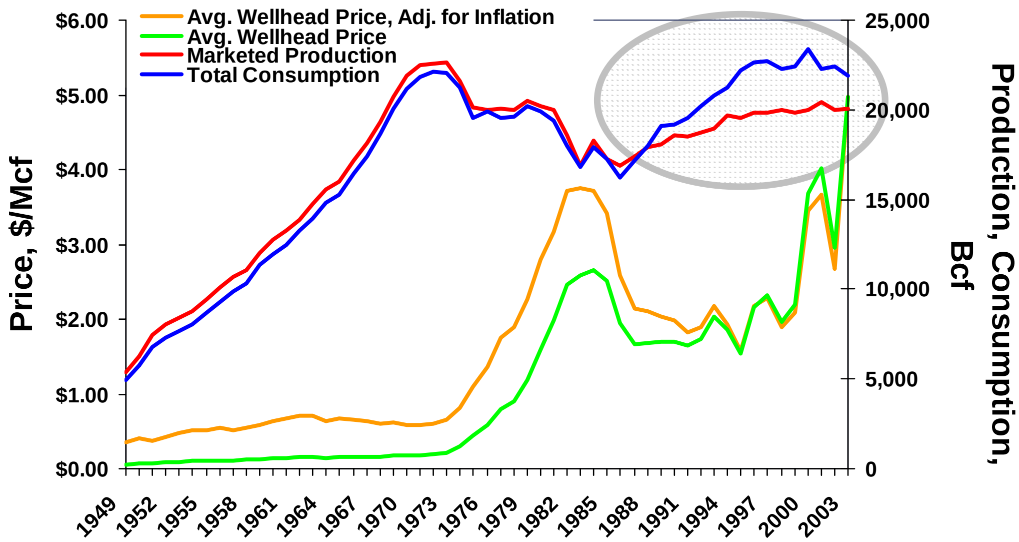


Source: U.S. EIA

A comparison of Figure 3, Figure 4 and Figure 5 gives insight into how the price spikes experienced between 2000 and 2004 resulted from the interplay between seasonal storage withdrawals and injections associated with distinct weather patterns (colder winters, warmer summers) and economic conditions in the United States. Importantly, supply and demand responses to higher prices also played a role. High prices during 2003 prompted demand to plunge – thereby opening a window for sufficient natural gas injections during the summer of 2003. Heating costs during the subsequent winter – while no bargain – were thus prevented from being even higher than they were.

How does the short term (post-2000) history compare with a longer term view? And what are the longer term indicators for U.S. and North American supply-demand balances? Figure 6 consolidates U.S. natural gas supply (domestic, marketed production) and total consumption, both in Bcf, with average wellhead prices earned by domestic natural gas producers, since the mid-1990s.

Figure 6. U.S. Natural Gas Supply, Demand and Price



Source: U.S. EIA

The long and complicated history of the natural gas industry in the United States mirrors those of other commodities: namely, it has been marked by policy and regulatory actions (many of them contradictory) that have affected both supply and demand.[11] Amid these various legislative initiatives and overall economic cycles, one fact stands out: *beginning in the late 1980s, consumption of natural gas in the contiguous United States began to exceed domestic supply*. To balance the market, natural gas exports from Canada began to play a critical role, growing from roughly 1.3 Tcf in 1988 to about 3.5 Tcf in 2003.

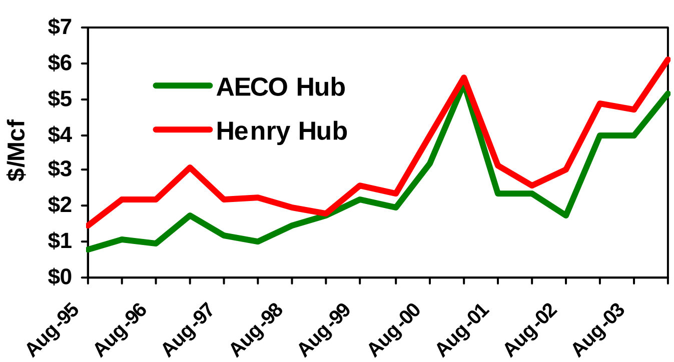
The U.S. supply-demand gap is more than persistent; it is expected to remain a permanent feature of the North American energy landscape, widening during periods of strong demand and narrowing as demand and supply adjust to higher prices. Long-term wellhead price trends reflect the relative availability of domestic supplies, as well as cycles in global oil markets (most notably the high-price periods

[11] A review of natural gas policy and regulatory history in North America is beyond the scope of this paper. For a synopsis of key policy and regulatory events in the U.S. natural gas industry, see CEE, 2003, *Guide to Electric Power in Texas*, http://www.beg.utexas.edu/energyecon/documents/guide_electric_power_texas_2003.pdf and Foss, et. al., North American Energy Integration, CEE, 1998. Also see the natural gas education web site, http://www.naturalgas.org/.

of 1973-1981, 1999-present; and low price periods of 1982-1992, 1998), since oil competes with natural gas in applications such as electric power generation. Against this backdrop, short term price volatility can be seen as reflecting longer term supply-demand balances.

Anyone looking for the source of natural gas pricing can choose from a full list of options: economic activity in the United States; seasonal weather patterns; oil prices; drilling and production trends; and evolving preferences with respect to how natural gas is used by industry and consumers. The truth is that all of these driving forces influence natural gas supply-demand balances and therefore prices. Regardless of their cause, the effect of natural gas pricing is immediate and inarguable. Prices are vital signals to both suppliers and users who respond accordingly: either by increasing demand and scaling back investments in development of new supplies when prices are low; or by decreasing demand and looking for new investment opportunities when prices are high. In the short term – during a calendar year and from season to season – weather is the variable that exerts the biggest impact on prices. Over the longer term, from year to year, historical trends in natural gas supply, use and storage can be useful tools in developing pricing models for the future.

Figure 7. Canada, U.S. Price Comparison



U.S., GOM Natural Gas Production

How do natural gas prices in Canada and Mexico compare with those in the United States? The strong link between prices in the United States and prices throughout the North American marketplace has already been noted. Figure 7 demonstrates the strong correlation between prices at Canada's main hub in the province of Alberta and Henry Hub. Prior to 1998, insufficient pipeline capacity existed to move natural gas from Alberta to the United States, and prices in Alberta were more strongly discounted relative to Henry Hub.

In Mexico, establishment of a regulatory framework in 1995 tied prices in that country to the United States via the Houston Ship Channel. This approach was used to determine prices for natural gas imported from the United States that competed with Mexico's own state-controlled production (see later section on Mexico).

Natural Gas Supply-Demand Trends and Outlooks

Given the escalation and volatility of gas prices experienced within the United States in recent years, active discussions are under way to develop new sources of supply, including expanding LNG imports. To understand the potential role of LNG, it is important to look more deeply at North American natural gas supply and demand trends and outlooks.

United States Overview

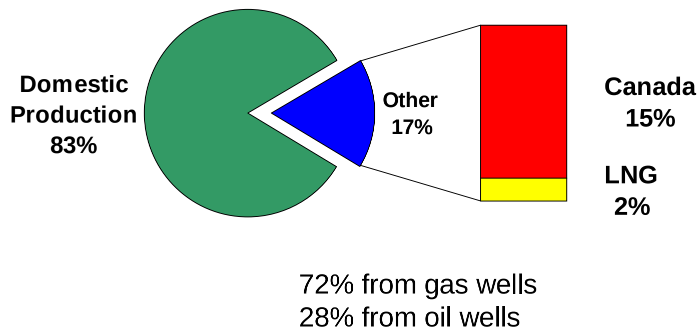
As already noted, natural gas consumed in the United States comes from three sources:

- Domestic production (with some placed in storage, including LNG, as described above);
- Net imports from Canada via pipelines; and
- Imports of LNG.

Domestic production is the largest source of natural gas supplies, providing 52 billion cubic feet per day (Bcfd), or 19 Tcf of "dry"[12] natural gas in 2003, as shown in Figure 8. The share of domestic production in total consumption has fallen to 83 percent in 2003 from a range of 95 to 99 percent in the early 1980s.

[12] "Dry" refers to a natural gas stream that is mainly composed of methane molecules and from which nonhydrocarbon molecules have been removed.

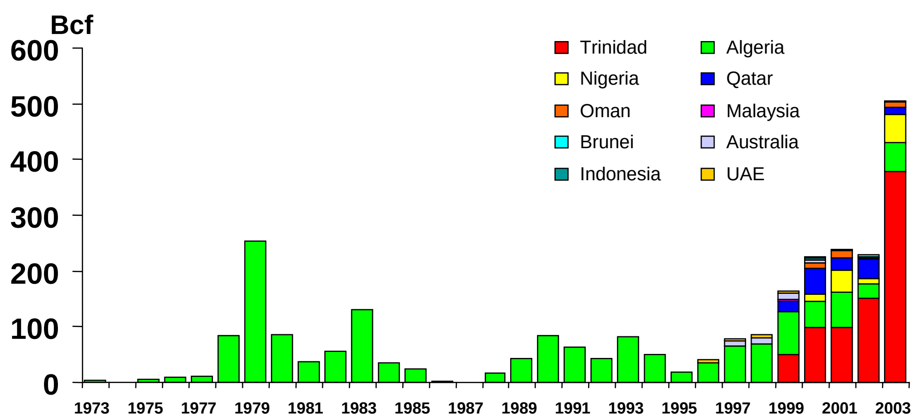
Figure 8. U.S. Natural Gas Supply (Consumption), 2003, (approx. 22 Tcf)



Source: U.S. EIA

LNG has historically accounted for less than one percent of U.S. consumption. Recent natural gas demand resulted in a record level of LNG imports in 2003, as shown in Figure 9.[13] *Imports of LNG to the U.S. in 2003 totaled 507 Bcf, which is more than double the previous record for LNG deliveries to this country in a single year.* In general LNG imports have increased since the mid 1990s and provided about two percent of U.S. natural gas consumption in 2003.

Figure 9. U.S. LNG Supply Trends



Sources: EIA, DOE

[13] U.S. EIA, *Natural Gas Weekly Update*, February 12, 2004.

The previous record was established in 1979, when the United States received 253 Bcf of LNG from Algeria. By 2003, supplies were received from vessels flying flags from Algeria and five other countries. In 2003,

- Algeria supplies totaled just 53 Bcf;
- Trinidad for the fourth consecutive year was the source country with the largest volume of exports to the U.S., delivering 378 Bcf in 173 cargoes. Supplies purchased from Trinidad accounted for approximately 75 percent of LNG imported to the United States.
- Other source countries included Nigeria (50 Bcf), Qatar (13.6 Bcf), Oman (8.6 Bcf), and Malaysia (2.7 Bcf) (also see Figure 2).

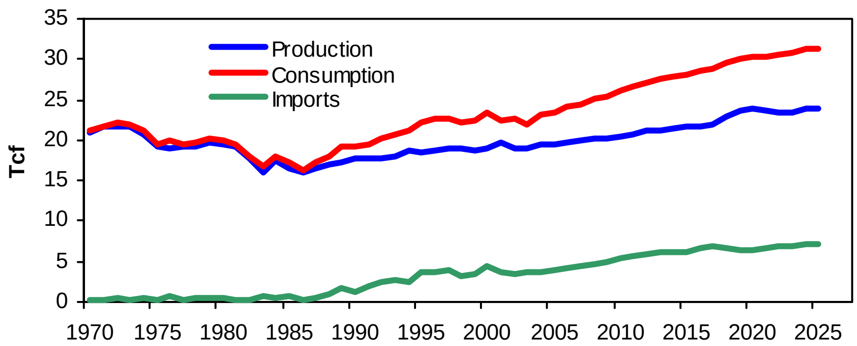
Southern Union's LNG terminal, located in Lake Charles, Louisiana, received the largest volume of any U.S. terminal in 2003 with receipts of 238 Bcf, all in the form of short-term or "spot" cargo sales. Distrigas (Tractebel), which operates the Everett terminal near Boston, Massachusetts, received 158 Bcf, all from Trinidad. Dominion Energy's Cove Point, Maryland, terminal, which re-opened in August 2003 for international trade, received 66 Bcf, while El Paso Energy's terminal on Elba Island, Georgia, also recently reactivated, received 44 Bcf over the year.

U.S. Supply Outlook

In its Annual Energy Outlook 2004 (AEO 2004) forecast as shown in Figure 10, the U.S. Energy Information Administration (U.S. EIA) suggests that the need for imports of natural gas will remain critical to balancing supply and demand in the United States.[14] (By envisioning no major changes in policy direction, the U.S. EIA Outlook extends the gap between domestic production and consumption throughout its forecast horizon.)

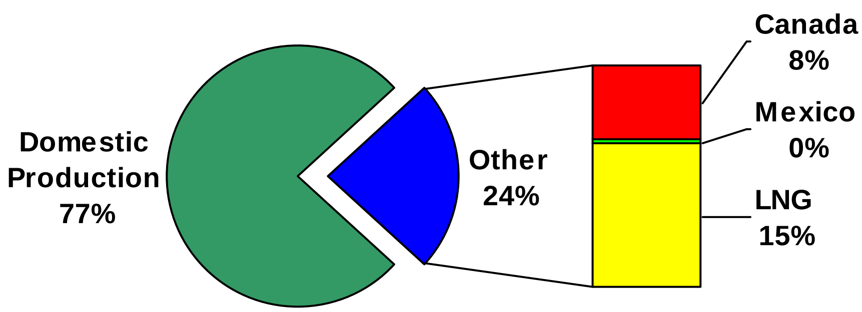
[14] See U.S. EIA, http://www.eia.doe.gov/oiaf/aeo/index.html.

Figure 10. Natural Gas Supply-Demand Outlook for the U.S. (Tcf)[15]



Source: U.S. EIA

Figure 11. U.S. Gas Supply (Consumption) Outlook, 2025 (approx. 31 Tcf)



Source: U.S. EIA AEO 2004

The U.S. EIA Outlook predicts that in 2025,

- The United States could import 7.4 Tcf of natural gas, double the 2003 level of imports;
- Imports of natural gas could account for 24 percent of total consumption,
- LNG imports could increase from two to 15 percent, and
- Canadian exports could decrease from 15 to eight percent.

A comparison of Figure 11 and the previous Figure 8 illustrates these changes. The U.S. EIA Outlook can be seen as an "educated guess" because it accounts for

[15] The U.S. EIA updates its long term forecasts each year. All forecasts are subject to change and reflect assumptions about factors impacting supply and demand as well as interactions among supply, demand and price based on best available information.

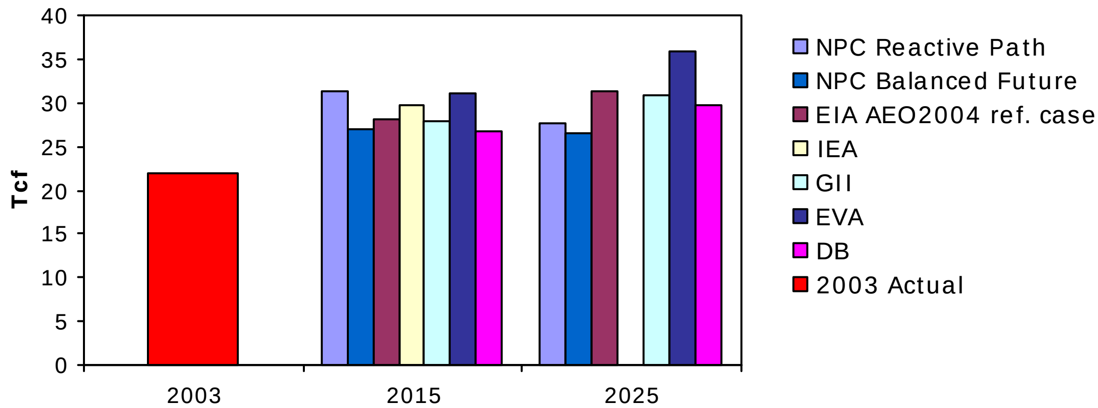
potential changes in natural gas prices, as well as technologies that influence patterns of use. Importantly, these anticipated increases in imports are seen as a necessary response to increased demand even though domestic production is also predicted to rise.

The patterns identified in outlooks produced by the U.S. EIA consider a number of factors:

- The dynamic national economy;
- A growing preference for using relatively clean-burning natural gas for environmental reasons;
- The lack of substitutes for natural gas for certain industrial applications;
- A dynamic demographic component for the United States (including high rates of in-migration, which keeps the U.S. population base relatively young as compared to other industrialized countries), and
- Strong patterns of single-dwelling home ownership.

The U.S. EIA is not alone in reaching these conclusions about the potential future of imports in general and LNG in particular. Figure 12 below compares forecasts for different time horizons by five organizations as compiled by the U.S. EIA and reviewed by the UH IELE.

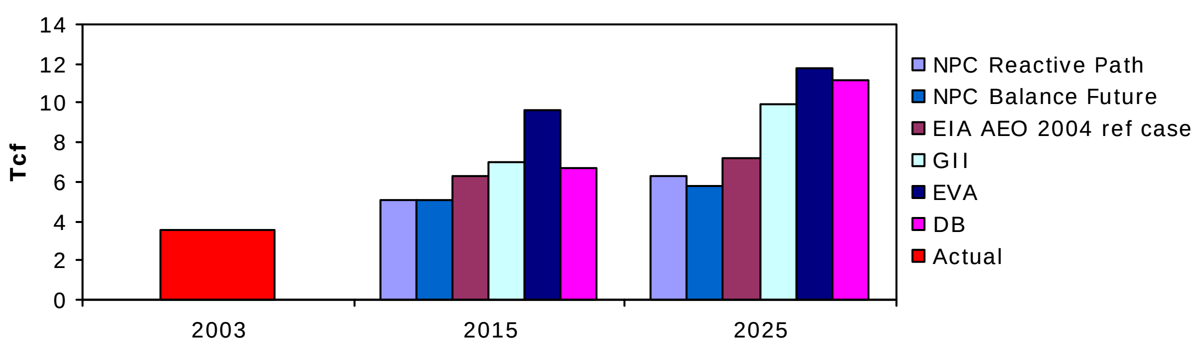
Figure 12. Comparative Forecasts of Natural Gas Demand (Tcf)[16]



Sources: EIA, IEA, NPC and others

The supply-demand gap for available comparative forecasts is shown in Figure 13 below as "implied imports." A consensus is that natural gas imports will surpass five Tcf by 2015 and six Tcf by 2025. This consensus is based on both established patterns of consumption – including demand-side responses to price fluctuations – and challenges in finding and delivering enough domestic production to meet demand.

Figure 13. Implied U.S. Natural Gas Imports (Tcf)



Sources: U.S. EIA, IEA, NPC and others

The projected increase in natural gas imports can be met through:

---

[16] The data are for Global Insight, Incorporated (GII), Energy Ventures Analysis (EVA), International Energy Agency (IEA), Deutsche Bank A.G. (DB), Energy and Environmental Analysis, Inc. (EEA), National Petroleum Council (NPC), and are available from U.S. EIA's Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/.

- Increased pipeline exports of domestic production from Canada;
- Mexico (which has a large natural gas resource base);
- Alaska (via Canada); and
- Increased LNG imports.

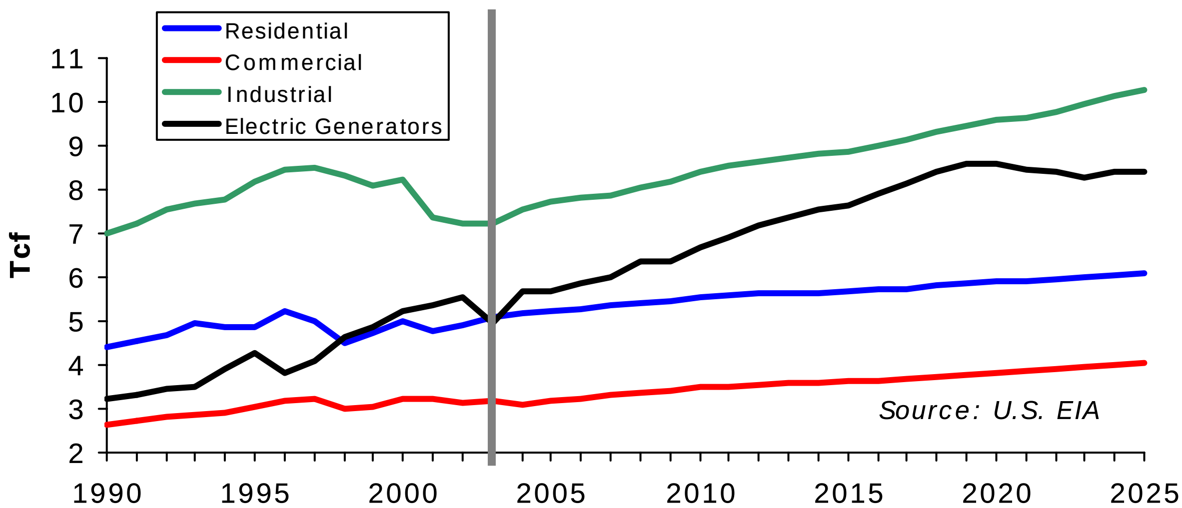
Alaskan natural gas also could be shipped to the Lower 48 states as LNG. The United States can receive LNG imports via Canada, Mexico or the Bahamas, or directly through terminals located in the Lower 48 states receiving shipments from a variety of producing regions around the world. All future outlooks for U.S. natural gas point to a need for continued healthy development of domestic resources through exploration and production drilling; capacity expansion of existing pipelines and LNG import terminals (to the extent that expansion is technically, commercially and environmentally feasible); and from new pipelines and LNG receiving terminals.

U.S. Demand Outlook

When assessing the outlook for natural gas consumption, it is important to separate the huge U.S. market into different types of customers in order to analyze the forces affecting natural gas use in different market segments. U.S. natural gas demand is usually divided into these four segments: residential; commercial; industrial; and electric generators. Figure 14 shows the consumption of natural gas by these four groups since 1990 with forecasts to 2025.[17]

[17] U.S. EIA, Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/.

Figure 14. Natural Gas Consumption by Sector (Tcf)



Residential

Residential consumers use natural gas as a fuel primarily for space and water heating. Together, these two uses account for more than 90 percent of the natural gas consumed by private households. Ten percent of residential use is for cooking, clothes drying and other activities. The primary drivers for long-term residential consumption are population and the energy efficiency and size of homes. In short term residential use of natural gas, weather is the most important variable.

Natural gas price increases and volatility since 1999 have not yet had a significant impact on residential demand, mainly because residential users are not able to switch fuels or change their consumption habits quickly without significant investment in new furnaces, insulation, or other conservation and efficiency measures. It also takes many years for the stock of housing available to U.S. households to turn over significantly. New "energy efficient" building designs, construction methods, and materials are always being developed – but all of them take time to introduce and win consumer acceptance. (And with natural gas costs representing a relatively small line item in the budgets of most consumers, there is no "price imperative" that can quickly galvanize consumers to change their purchasing habits.) The U.S. EIA projects that residential demand for natural gas will remain relatively stable, growing at 0.9 percent a year, from a little less than five Tcf in 2003 to 6.09 Tcf in 2025.[18]

Commercial

The two largest commercial uses of natural gas are space and water heating, which account for more than 60 percent of total consumption in this market segment. Other usage includes pumps; emergency electric generators; combined heat and power in commercial buildings; and manufacturing performed in commercial buildings. Just as in the case of residential users, commercial users have not markedly changed consumption patterns in response to higher costs for natural gas since 1999. Commercial demand for natural gas is projected to rise from about 3.17 Tcf in 2003 to over 4.0 Tcf by 2025 according to the U.S. EIA.

Industrial

Industrial users employ natural gas as a source of energy (fuel) and as a chemical feedstock. Roughly one-third of all the energy used by the U.S. industrial sector comes from natural gas, mainly as a fuel for heating. Additionally, natural gas is a key ingredient for the petrochemicals industry, which uses more than 90 percent of the natural gas consumed as industrial feedstock in the United States. Unlike residential and commercial users, industrial customers are very sensitive to fuel costs and usually have the ability to switch fuels and a greater incentive to invest in conservation and efficiency measures in response to high prices. However, it is more difficult for industrial customers to change from natural gas as a feedstock.

In contrast to residential and commercial demand, industrial consumption fell from 8.25 Tcf in 2000 to 7.35 Tcf in 2001 – a nine percent drop. The recent peak in industrial demand for natural gas was 8.51 Tcf in 1997; since then, demand has been declining steadily. Nevertheless, the U.S. EIA expects a recovery in industrial use, mainly as prices moderate with increased supplies, and a consumption level of

---

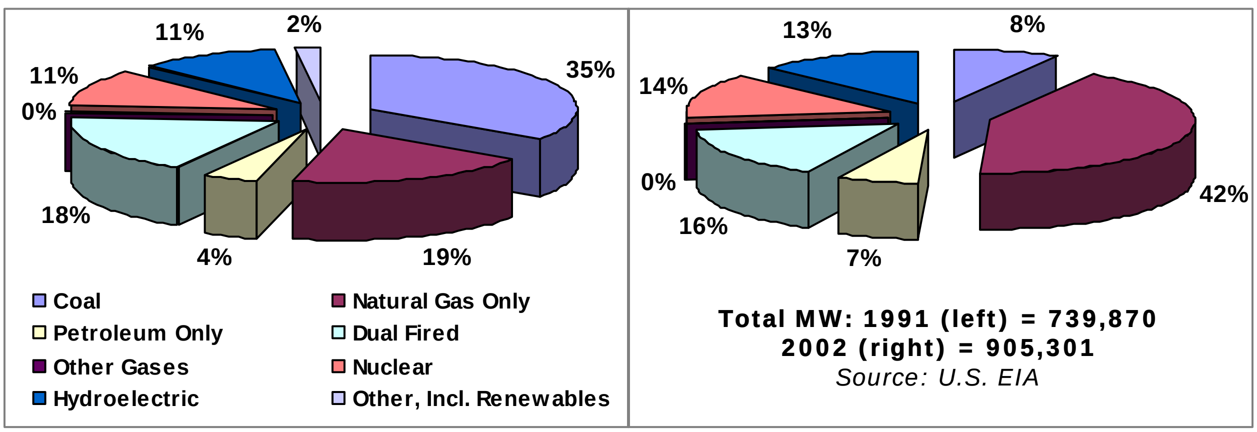
[18] U.S. EIA - Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/

10.29 Tcf by 2025[19]. In contrast with the EIA outlook, the NPC study assumes flat industrial demand in a "balanced future" case.[20]

Electric Power Generation

The amount of electricity produced from natural gas increased by nearly 50 percent between 1991 and 2002, from about 382 million megawatt hours (mwh) to just over 691 million mwh. This represents a significant increase in natural gas use in the United States, and it contributed to a 33 percent growth in natural gas consumption during this time period. The net natural gas-fired generation capacity for summer – critical for peak-period demand associated with air conditioning – more than doubled during the 11-year period, from 60.8 million kilowatts in 1991 to more than 171 million kilowatts in 2002.[21] Figure 15 shows the growth in natural gas compared to other fuels for power generation between 1991 and 2002.[22]

Figure 15. U.S. Net Summer Electricity Generation Capacity, 1991 (left) and 2002 (right), in megawatts (MW)



A number of elements are behind the strong growth in demand for natural gas for electricity generation:

- Advances in natural gas turbine technologies, in particular combined cycle gas turbines which are extremely "energy efficient."

---

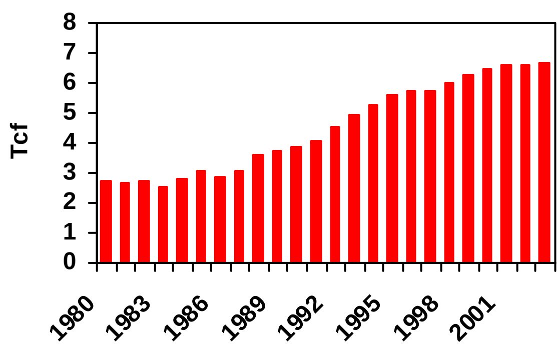
[19] U.S. EIA - Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/
[20] See www.npc.org.
[21] Data from U.S. EIA: http://www.eia.doe.gov/cneaf/electricity/epa/epates.html
[22] Net natural gas electric generation capacity for winter heating is also important, especially for regions like New England. However, the electric power industry and U.S. EIA does not provide this data separately.

- New policy incentives, including termination of prohibitions on natural gas use.
- Creation of competitive wholesale markets for electric power (through the 1992 Energy Policy Act and related actions by the U.S. Federal Energy Regulatory Commission or FERC).[23]

Projections of increased demand for electric power have been key drivers for both natural gas resource development and for expectations about the need for future LNG imports. Consumption of natural gas by these generators could be the most significant driver of future demand growth, potentially even offsetting any recession-driven declines in industrial consumption. (The caveat is that natural gas prices could rise to the point where utilities would seek alternative fuels for power generation.) The U.S. EIA estimates demand by electric generators to increase from roughly five Tcf in 2003 to about 8.4 Tcf in 2025, an increase of nearly 70 percent.

Canada Overview

Figure 16. Canadian Natural Gas Production



Source: U.S. EIA

Canada's natural gas market dynamics deserve attention. Canada exports a large volume of natural gas to the United States and plays an important role in "balancing" the North American marketplace. The country has extensive proved natural gas reserves and resources, and it is a net exporter of natural gas to the United States. Proved natural gas reserves in Canada were estimated at 59 Tcf at December 2003.[24] Canada produced about 7.0 Tcf and consumed almost 3.0 Tcf in 2002, with 3.8 Tcf exported to the United States (see Figure 16 above). In a recent report, the National Energy Board (NEB)

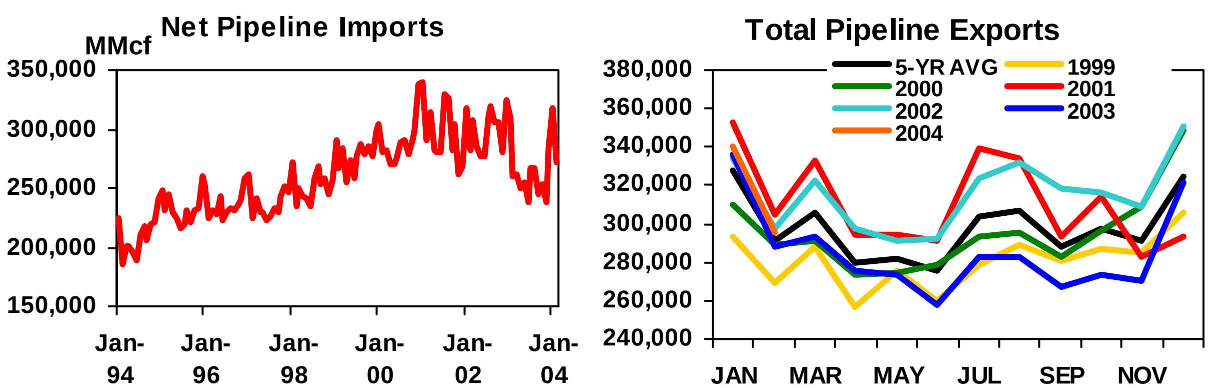
---

[23] See CEE, 2003, *Guide to Electric Power in Texas*, for descriptions of these and other national and state level policy changes that have impacted both natural gas use for electric power generation and restructuring of both the natural gas and electric power industries in the U.S. (note 11).
[24] Oil & Gas Journal, *Worldwide Look at Reserves and Production*, Dec. 22 2003.

of Canada estimated the total resource base of the country at between 548 Tcf and 596 Tcf; the higher resource number assumes that future developments in technology will lead to more effective exploration and development of resources.[25]

Figure 17 indicates the impacts of both long-term and short-term natural gas market dynamics on net pipeline imports by the United States and total exports from Canada. Net pipeline imports by the United States grew rapidly during the 1990s but are flat to declining in the 2000s. (Seasonal cycles exert a substantial influence on Canada's usage patterns, with heating requirements boosting demand in winter, and storage "refills" and electric power generation driving demand for gas in summer.)

Figure 17. U.S. Net Pipeline Imports from Canada Total Pipeline Exports from Canada



Sources: U.S. EIA and NEB

Figure 18 shows estimates of U.S. imports of natural gas from Canada. The U.S. EIA forecasts that annual exports of natural gas from Canada will fall to 2.56 Tcf by 2025.[26] The NEB and the Canadian Energy Research Institute (CERI)[27] recently completed independent analyses of Canadian production and consumption. The

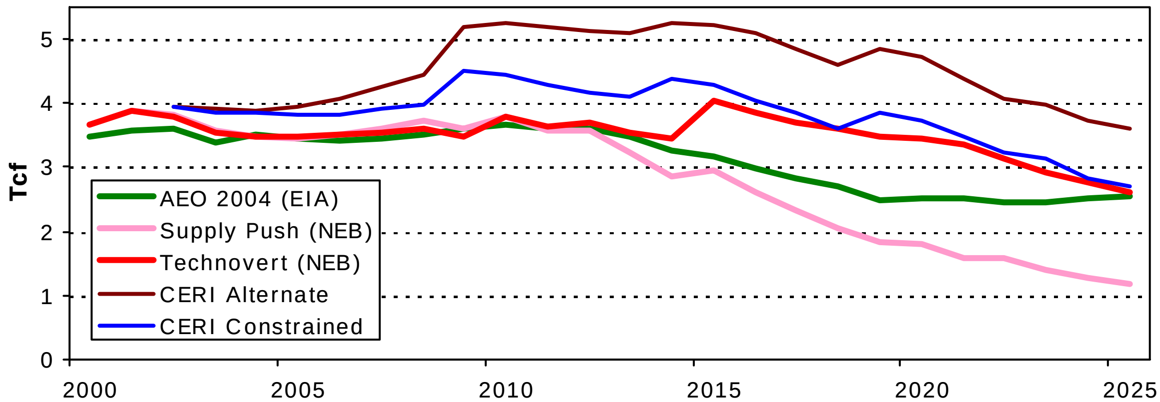
[25] National Energy Board of Canada Canada's Energy Future: Scenarios for Supply and Demand to 2025. http://www.neb-one.gc.ca/energy/SupplyDemand/2003/English/SupplyDemand2003_e.pdf. "The Supply Push (SP) scenario represents a world in which technology advances gradually and Canadians take limited action on the environment" (p. 16) and "the Techno-Vert (TV) scenario is a world in which technology advances more rapidly. In addition, Canadians take broad action on the environment" (p. 20).

[26] U.S. EIA - Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/.

[27] CERI studied two scenarios. The "Alternate" case assumes supplies from unconventional resources and increased drilling activity. The "Constrained" case assumes lower levels of unconventional production and drilling. For details, see "Potential Supply and Costs of Natural Gas in Canada" in the fourth quarter 2003 issue of the IAEE Newsletter.

forecasts from these two studies were used to estimate natural gas volumes that could be available for export. The results are shown in Figure 18 and are compared with estimates from the U.S. EIA projection.

Figure 18. U.S. Imports from Canada



A large gap of more than two Tcf separates the CERI Alternate scenario and the NEB's Supply Push scenario after 2010 - indicating a significant level of uncertainty regarding volumes of natural gas that may be available from Canada. Developing consensus on these future volumes is made more difficult by changing trends in Canada's natural gas marketplace. On the supply side, attention has always focused on Canada's massive but maturing Western Sedimentary Basin, the main driver for natural gas production and exports, and the focus of a later discussion on supply issues in **Appendix 1: Supporting Information on** North American Natural Gas Supply-Demand Issues Identifying, accessing and producing gas from other environmentally sensitive regions in Canada is far from a certain bet. On the demand side, Canada's domestic consumption of natural gas grew by more than one-third between 1980 and 2002. Many of the same forces driving natural gas demand in the United States were behind this surge, including a preference for natural gas for electric power generation in many locations and, importantly, increased use of natural gas for industrial applications (including expanding operations at northern Alberta's tar sands and oil sands projects and petrochemical operations throughout Canada). Considerable debate is underway about the extent to which growth in domestic consumption and the challenges of exploiting the significant reserves in Canada's environmentally sensitive regions to the far north and offshore will constrain or contribute to future deliveries of natural gas.

Mexico Overview[28]

If the future of Canadian supplies can be described as "uncertain," then the future of natural gas in Mexico remains an enigma wrapped around a riddle. How the riddle is answered will have significant repercussions throughout North America.

Mexico sits atop the sixth-largest proven reserves in the Western hemisphere. Mexico reported proved natural gas reserves of 15 Tcf in December 2003, with production of about 1.3 Tcf per year and consumption of about 1.4 Tcf per year.[29] Natural gas trade between the United States and Mexico is bi-directional, but Mexico has been a net importer for some time. Indeed, a growing gap between consumption and production in Mexico that is projected to continue for several years will undoubtedly exacerbate the U.S. supply-demand imbalance. Information from Mexico's Secretaría de Energía (SENER) indicates that Mexico's demand for natural gas will grow at an average of 6.8 percent per year through 2012, reaching 9.4 Bcfd in that year from 4.9 Bcfd in 2002. As is the case with its neighbors to the north, electrical power generation is the primary driver of natural gas demand in Mexico. Economic growth imperatives and environmental considerations (a national effort to pull the plug on electrical power generated by heavy fuel oil) are expected to boost gas consumption for power generation by an average of 10.8 percent per year. Meanwhile, domestic production is forecast to grow by 5.1 percent per year, from 4.1 Bcfd in 2002 to 6.8 Bcfd by 2012, well under Mexico's projected demand.

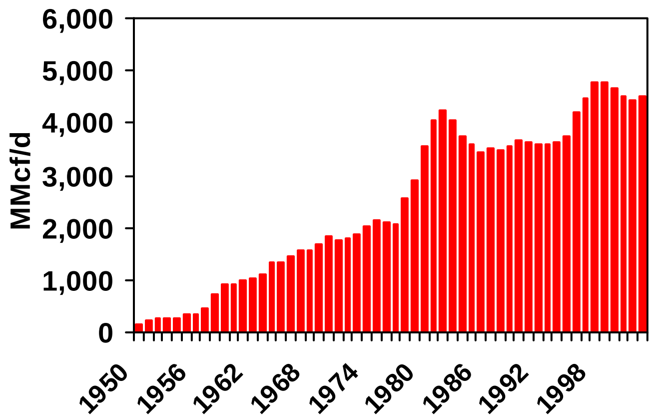
---

[28] All information in this section is based on ongoing analysis of Mexico conducted by the CEE. In particular, see Foss and Johnson, 1991, The Economics of Natural Gas in Mexico, *Proceedings of the 13th Annual North American Conference*, International Association for Energy Economics, Chicago, Illinois; Foss, Johnson and García, The Economics of Natural Gas in Mexico – Revisited in *The Energy Journal*, special volume on North American Energy Markets After Free Trade, v. 13, n. 3; and Foss, et. al., *North American Energy Integration: The Prospects for Regulatory Coordination and Seamless Transactions of Natural Gas and Electricity,* final report, Shell Interdisciplinary Scholars Grant, CEE, 1998. For more information on CEE experience in Mexico, see www.beg.utexas.edu/energyecon.

[29] Oil & Gas Journal, *Worldwide Look at Reserves and Production*, Dec. 22 2003. The current reserves for Mexico reflect a more than 90 percent reduction from PEMEX's official estimate in 1998, the result of an effort to correct chronic over-reporting by the Mexican government as the country sought loans from money center banks during the 1970s.

By 2012, expectations are that Mexico will be importing about 2.6 Bcfd to balance its market and meet new demands.[30]

Figure 19. Mexico Natural Gas Production



Source: Pemex

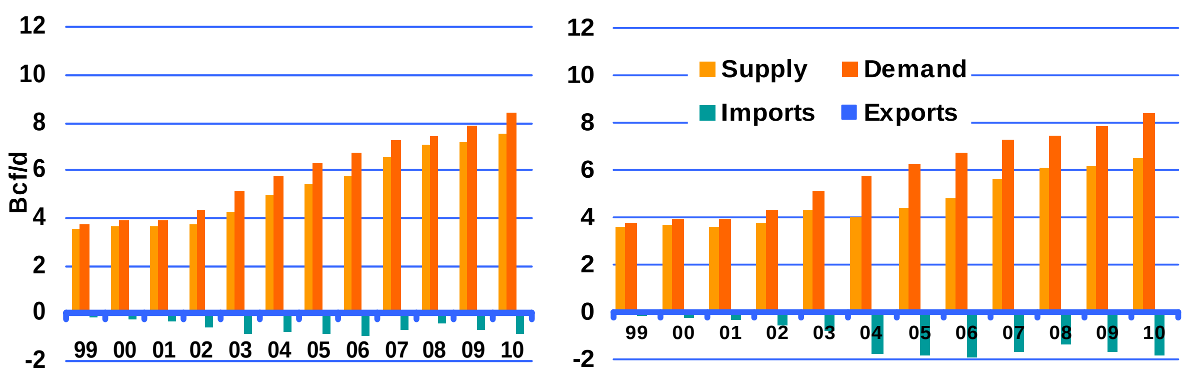
In spite of abundant of natural gas resources throughout Mexico, the country's production quantities have remained relatively flat for the past 20 years (see Figure 19 at left). Observers point to the organization of Mexico's energy sector as the source of this languorous performance. Mexico's constitution and associated regulatory law mandate national government control not only of oil and gas exploration and production activity, but also of refining and marketing of crude oil and basic petrochemicals which use natural gas feedstock. These policies were established during the 1938 nationalization of Mexico's oil and gas sector and formation of the republic, and so bear the burden of history. In 1995, an amendment to the constitution removed natural gas pipelines, local distribution networks (utilities) and natural gas storage from the exclusive domain of the state. All upstream activities remain reserved to Petroleos Mexicanos or PEMEX, Mexico's national oil company and the single largest generator of export revenue (through crude oil sales) and therefore hard currency for the country. PEMEX's revenues account for nearly 40 percent of Mexico's general treasury. Most of this wealth is captured for social spending, leaving 30 percent or less for re-investment by PEMEX.

Years of meager capital spending have done little to expand Mexico's natural gas production base for domestic use, much less cultivate it for export. With increased investment, Mexico could produce enough natural gas to meet domestic supply and potentially sell its entire surplus to customers in the United States. But there is

[30] Mexico's Secretaría de Energía (SENER) - Natural Gas supply – demand balance 2002 – 2012 (Reference Case). Data provided by SENER.

considerable doubt about Mexico's ability to attract private-sector financing to supplement PEMEX's own funding, given existing policy constraints and political sensitivities. PEMEX is attempting to experiment with a form of multiple services contract for E&P that would facilitate some private participation, but even this approach is meeting political resistance.[31] At least one scenario points to what could be accomplished with such a contract in place and successful projects underway (Figure 20 below). With additional private investment – and the introduction of LNG facilities to process and deliver gas from remote fields – Mexico could resume its status as a net exporter of natural gas.

Figure 20. Mexico's Supply-Demand Balance with the MSC (Left) and Without the MSC (Right), Bcf/d



Sources: PEMEX, SENER (provided by Alpek Corp.)

Summary – Key Points about North American Natural Gas Supply and Demand

Several factors are worth considering when it comes to long term natural gas supply-demand balances in North America. Details on these factors are provided in **Appendix 1: Supporting Information on** North American Natural Gas Supply-Demand Issues, which provides an analysis of natural gas market conditions that could have a significant effect on future outlooks. With respect to continental supplies, the following key points apply.

---

[31] PEMEX hopes to attract $10 billion per year in new funding for E&P through its Multiple Services Contract. See http://www.csm.pemex.com/english/index.html. Arguments against the MSC target legal legitimacy of this approach given constitutional restrictions on hydrocarbons in Mexico.

Key Considerations for Supply

The United States is experiencing both depletion and steep decline curves in established fields, and also lower rates of productivity in new gas wells. Given the maturity of U.S. basins, much attention has focused on the level of natural gas drilling that must be maintained in order to ensure "deliverability."[32] Natural gas drilling hinges on the economic viability of wells and new prospects. Prolonged periods of low prices relative to costs and other factors discourage drilling. A key issue is whether new drilling will yield new natural gas production at rates equivalent to historical patterns. Indications are that productivity for new onshore U.S. wells may not reach the rates of production achieved in the past.

Similar trends are at work in Canada. In general, producers in the vast Western Sedimentary Basin face declines in established fields and lower initial production rates for new wells. The Canadian resource base remains hugely attractive for investment, notwithstanding disappointments offshore Atlantic Canada, and the costs and uncertainties associated with coal-seam gas in Canada's western provinces.

Mexico represents an alluring prospect for new natural gas production, but political constraints have prohibited expansion of that country's natural gas deliverability. In all three countries, policymakers are searching for ways to support upstream development in maturing basins and develop new ways of exploiting unconventional natural gas resources.[33]

Current and recent high prices in the United States might reflect a "rebound" from the prolonged effect of the "gas bubble." The "bubble" of oversupply was a major driver for consolidation in the exploration and production segment for both operating and service companies, with surplus deliverability and

---

[32] Deliverability refers to the number of future years that a natural gas field, pipeline, storage or other facility can meet its annual requirements for its presently certified capacity.

[33] As noted in **Appendix 1: Supporting Information on** North American Natural Gas Supply-Demand Issues, unconventional natural gas resources include coal seam gas (or coalbed methane, CBM) and tight sands and shales.

low natural gas prices effectively discouraging investment and drilling activity. Introduction of open access[34] as a specific policy goal helped reduce surplus deliverability, as did the expansion of gas-fired electric power generation capacity (a development encouraged by low natural gas prices).

Increased volatility of natural gas prices may also affect drilling activity. When natural gas prices ramped up in 2000-2001, U.S. and Canadian producers stepped up drilling activity in marginal natural gas projects that *required* higher price levels to be economic. When prices quickly collapsed, producers that had not hedged[35] were locked into expensive ventures where invested capital was generating poor returns.

E&P for natural gas is driven not only by expectations for natural gas prices, but also for oil prices, because natural gas is often produced in association with crude oil and often competes with oil at the "burner tip." In 2003, 26 percent of U.S. natural gas production was derived from oil wells as associated gas. More than 50 percent of Mexico's natural gas is associated with crude oil production. Oil is a fungible global commodity that has its own supply-demand interactions.

The Organization of Petroleum Exporting Countries (OPEC) has a large impact on both current and expected future prices of oil, and therefore indirectly on natural gas prices in North America and elsewhere. Natural gas prices tend to be higher during periods of firm oil prices. OPEC decision-making is opaque, adding an element of uncertainty to future oil prices and thus impacting drilling decisions and, indirectly, natural gas production.

---

[34] Open access is a regulatory mandate implemented by the U.S. Federal Energy Regulatory Commission (FERC) to allow others to use an interstate pipeline's transmission facilities to move bulk natural gas from one point to another on a nondiscriminatory basis for a fee. For more information, see CEE, *Guide to Electric Power in Texas* or www.naturalgas.org (footnote 11).

[35] Hedging is defined as the purchase or sale of a futures or option contract as a temporary substitute for a cash transaction to be made at a later date. It is a strategy designed to reduce investment risk associated with changing commodity prices.

The collapse and prolonged slump in oil prices from the mid-1980s until the most recent high price cycle initiated in late 1999 aggravated (some would say "caused") E&P industry consolidation and hindered drilling investment.

***Timing to add additional pipeline capacity to serve new producing areas, especially frontiers*.** Natural gas producers and customers are now required to enable pipeline projects by executing long-term transportation commitments.

Producers in the remote locations must also deal with higher and more volatile "basis differentials" – defined as the difference in the market value of natural gas at two separate physical locations at the same point in time. Basis differential is used as a proxy to establish the market value of pipeline transportation between those two locations at that time. Much of the basis differential for natural gas produced in the U.S. Rocky Mountain region, for example, stems from "distance away from markets" and associated pipeline transportation capacity and cost.

Producers would like to achieve the higher "netback price" (the value of natural gas production in the field minus transportation cost) that initially attends new pipelines and the elimination of existing transportation constraints and bottlenecks. Customers would like access to relatively cheaper Rocky Mountain natural gas supplies. Over time, natural gas prices in other regions of the United States could be moderated by improving pipeline access to supplies in locations like the Rockies.

In regions outside of the U.S. Rockies, large pipeline projects to serve new, prolific fields in the deepwater U.S. Gulf of Mexico, Canada's far north and Alaska will require long lead times. Developers of these projects must surmount a number of hurdles, ranging from funding for project investment to technological advances (for deep sea and permafrost construction) to development of appropriate policy and regulatory regimes and coordination for new transportation corridors.

Key Considerations for Natural Gas Demand

Adjustments on the demand side offset tensions on the supply side. In any open, competitive market, consumers will adjust their demand for a commodity according to price (and their willingness to pay, subject to other considerations such as income, sensitivity to changes in price, access to substitute fuels, etc.). Since 2000, it is clear that some consumers have reacted to higher natural gas prices by switching to other fuels, consuming less through conservation and increasing efficiency or even shutting down capacity. Most of this demand reduction appears in the industrial sector where natural gas is used both as a feedstock and as a fuel. Natural gas is also an important fuel in basic manufacturing industries like steel. Across North American, rapidly rising prices have had a large impact on industrial customers. While demand-side adjustments are important and should be expected, they also represent lost economic activity and capacity.

Natural gas use for electric power generation has increased dramatically since the 1980s. Increased use of natural gas for power generation is a consequence of the environmental benefits of this relatively clean-burning fossil fuel; the lower costs to build new natural gas-fired power generation plants relative to other technologies; and the improved technologies of high efficiency natural gas electric power turbines. The role of natural gas-fired power generation in the future is mixed. In most regions of the United States, natural gas-fired power plants are the "marginal generators," producing electricity for dispatch into the marketplace during peak periods of electric power demand. During these peak periods, both electricity prices and natural gas prices may be higher as a result of demand.

In many parts of the United States, older, less-efficient power plants (including those that use natural gas) are being replaced by newer, high-efficiency natural gas turbines. These newer turbines help to moderate use of natural gas for power generation and peak-period prices for electricity. In Mexico, with its fast- growing, young population and thirst for clean energy, the emphasis on natural gas-fired power is a matter of policy. While alternative fuels, including coal (for conventional thermal power plants and new gasification technologies) are part of Mexico's fuel mix, natural gas remains a state-driven priority.

Balancing North American Supply Requirements with LNG

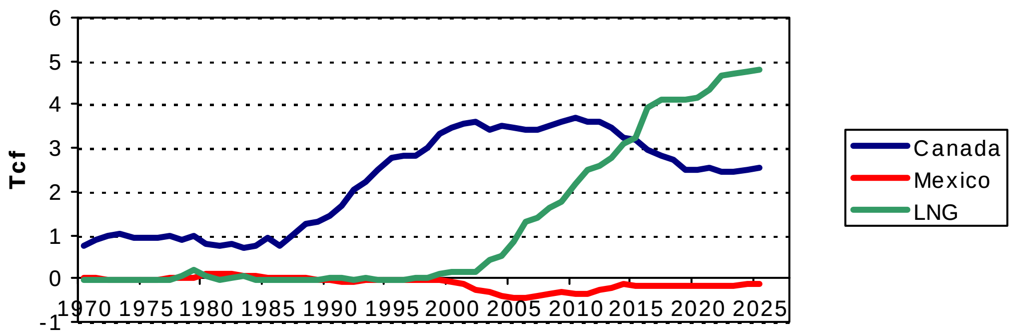
Overview

Across North America, consistent themes emerge with regard to natural gas resources and how they are used:

- Natural gas is often termed a premium commodity for its value as both an energy source and as a feedstock, and because it is relatively clean-burning. As a result, natural gas is relied upon for a wide variety of applications: direct use in home and business heating; electric power generation; and the manufacture of everything from plastics to fertilizers and intermediate materials. Much of the demand for natural gas is "inelastic," meaning less responsive to price, with residential heating being a good example. Industrial use of natural gas, however, is very sensitive to price, as is electric power generation.
- Growth in natural gas production on the continent has not kept up with demand for many reasons, including a long period of low gas prices from the early 1980s until the mid 1990s; maturity of key producing basins and fields in the United States and Canada; limited access to prospective areas for drilling; capital constraints on drilling; and policy and political restrictions in Mexico. Both the United States and Mexico are net importers, while exports from Canada help to balance the continental marketplace.
- The North American continent is rich in natural gas, both in proved reserves and resources that could be developed under a range of scenarios that incorporate attractive prices for producers and continued technological advances that enable commercial recovery of natural gas from technically challenging reservoirs.
- Even with a rich resource base, a number of distinct challenges affect the outlook for domestic production, including some of the most promising areas (Alaska, Canada's frontier and the U.S. deep and ultra deep Gulf of Mexico). As a result, LNG is recognized as an important option for meeting U.S. natural gas supply requirements.

For the huge U.S. market, one view of how supply and demand dynamics might play out is shown in Figure 21 below. According to the U.S. EIA outlook, Canadian exports begin to decline with continued maturity of Canada's main producing basin; Mexico remains a nominal net importer; and LNG shipments accelerate to take up the slack.

Figure 21. Net Natural Gas and LNG Imports to U.S. (Tcf)



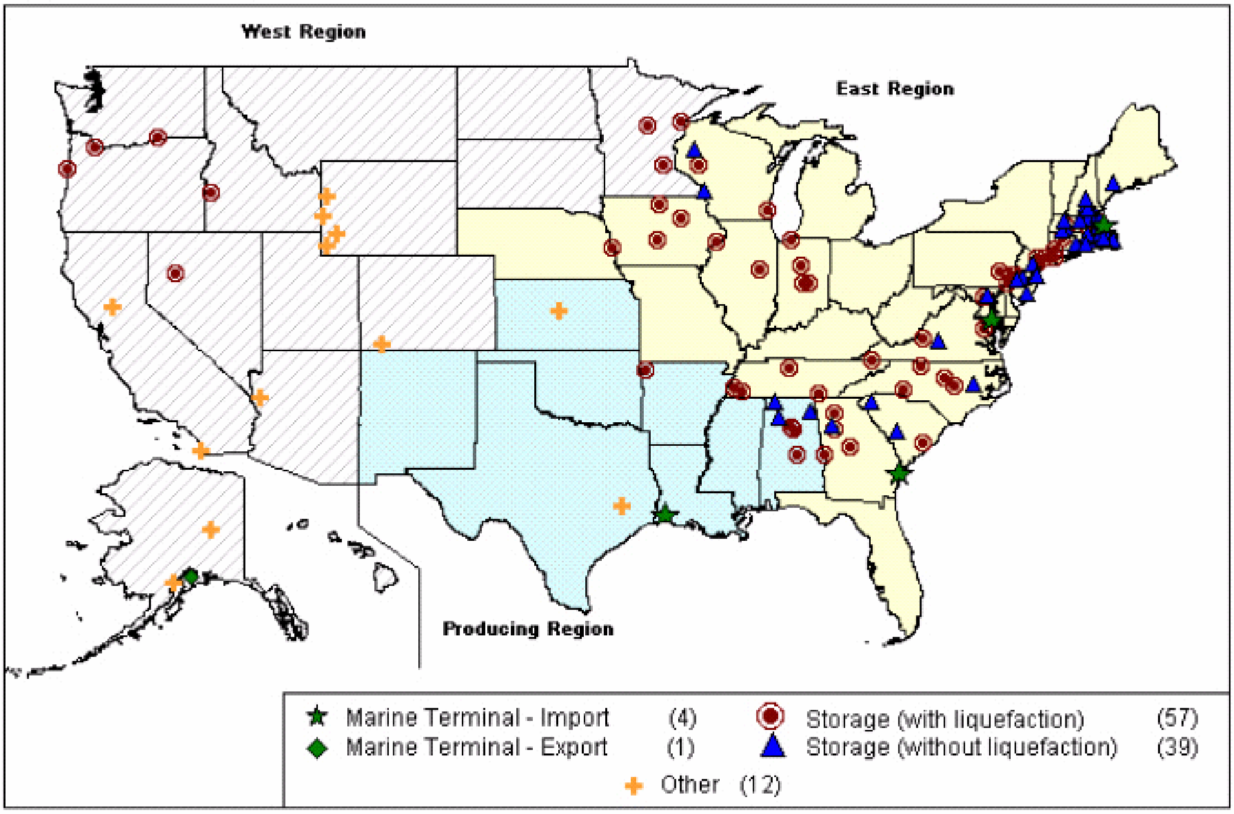
Source: EIA AEO 2004

LNG Facilities

The U.S. has numerous, diverse LNG facilities that help balance natural gas supply and demand, as shown in Figure 22. More than 100 LNG facilities are in operation, representing the largest LNG network in the world. Most of these are peak-shaving facilities used by utilities to store domestic production. Four import terminals (for receiving and regasification) operating on the mainland of the United States and one in Puerto Rico are capable of sending out 2.3 Bcf/d (or 0.84 Tcf a year) and 3.2 Bcf/d on peak days, with 19 Bcf of total storage capacity.[36]

[36] For details on U.S. LNG facilities and operations, including safety and security, see CEE *Introduction to LNG* and *LNG Safety and Security*, www.beg.utexas.edu/energyecon/lng.

Figure 22. U.S. LNG Facilities as of June 2004[37]

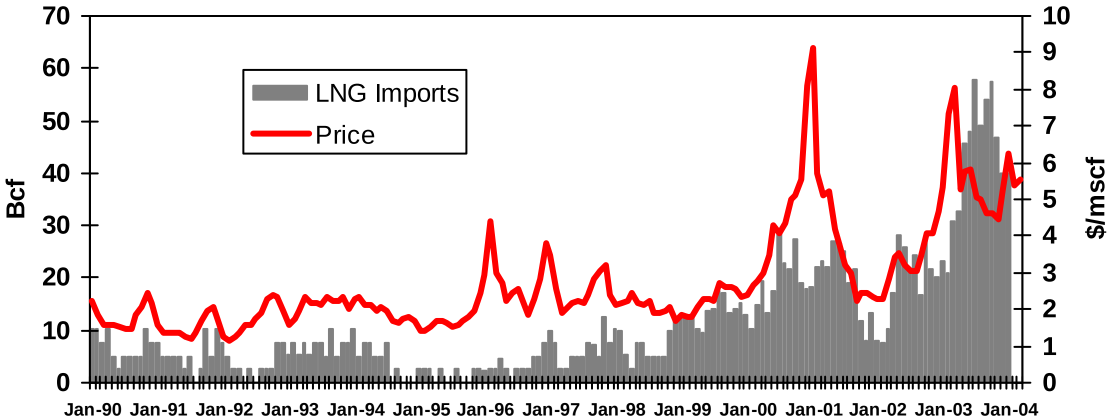


Notes: Map excludes the import facility in Puerto Rico. Other includes: stranded utilities, vehicular fuel facilities, nitrogen rejection units and other special processing plants.
Sources: Energy Information Administration, Office of Oil and Gas, and industry sources.

Currently, LNG imports answer about two percent of U.S. natural gas needs. But, as shown in Figure 23, imported LNG was a significant incremental source of supply during the tight market conditions witnessed since 2000. In contrast to the 1990s, LNG cargos continued to arrive in the United States even when natural gas prices declined because new LNG supply sources remained viable and economic even in the face of dropping prices.

[37] EIA: *U.S. LNG Markets and Uses: June 2004 Update*

Figure 23. Natural Gas Price (Henry Hub Cash Market) and LNG Imports



Source: U.S. EIA and NGW

To accommodate an increase in imported LNG, North America must increase its receiving and regasification terminal capacity. Some of this capacity increase could be attained through expansion projects at existing facilities. New facilities will be needed, and a number of new marine import terminals have been proposed and approved – not only in the United States but also in Canada and Mexico.[38]

Clearly, how many projects are built depends upon demand for all of the capacity that would be developed. Based on the low scenario indicated in Figure 13 (an implied requirement of 4.8 Tcf of LNG by 2025), up to seven terminals averaging one Bcf/d capacity each might be needed. A number of risks surround the potential development of new LNG import capacity. For example, natural gas market dynamics (shifts in supply, demand and thus price) could occur that would alter the outlook for increased imports. Difficulties in siting and permitting new import terminals could delay growth in LNG imports, possibly contributing to supply disruptions and higher prices, especially in regions that are far from domestic production sources (such as the densely populated U.S. Northeast).

[38] For regular updates refer to http://www.ferc.gov/industries/gas/indus-act/lng-what.asp and the LNG briefing, http://www.ferc.gov/industries/gas/indus-act/lng-briefing.pps.

Of note are proposals to build LNG import facilities in Canada and Mexico. The lackluster performance of natural gas drilling activity offshore Atlantic Canada has triggered interest in LNG projects. As this report is published, the expectation is that a project in New Brunswick province could reach final approval by fall 2004, and a project in Nova Scotia could receive environmental approvals by end of summer 2004.

Currently, an agreement is in place for a regasification terminal in Altamira on Mexico's Atlantic coast that would be capable of supplying at least 0.15 Tcf a year. Proposed LNG receiving terminals in the Baja region could export surplus natural gas to California and provide incremental supplies to balance western natural gas markets in the years ahead. Additional proposed terminals further south on Mexico's Pacific coast and in the Yucatán would provide indirect support to North American natural gas balances by serving growing natural gas demand elsewhere in Mexico.

LNG Cost and Price

The LNG value chain requires investment commitments from all involved parties. However, the cost estimates for importing LNG are considerably less than when the LNG industry was launched roughly 40 years ago. Substantial savings have been achieved in both liquefaction technologies and shipbuilding, and the life spans of LNG tankers have been extended substantially. Today the LNG value chain incorporates significant technology improvements for cost reductions and economies of scale, as well as enhancements and protections for health, safety and the environment. Overall, the average costs for liquefaction, shipping and regasification of LNG have declined. Representative costs to develop the LNG value chain are shown in Figure 24. It is important to note that these cost ranges are estimates only and are based on quoted information that can differ substantially from project to project and country to country. In particular, variation in the cost for natural gas feedstock (production) hinges on the terms that governments offer for E&P activity. Shipping costs vary based upon shipping distance and size and type of vessel.[39] A number of different approaches are being evaluated for receiving, regasification and storage (including the possibility of locating these activities offshore) so that the cost range for that segment might change significantly in the future. The final delivered cost of natural gas from LNG imports also depends on the distance separating customers from major import facilities. The cost estimates provided by UH IELE do not include any taxes or fees that might be imposed on LNG cargoes, and exclude some operations and maintenance costs.

Figure 24. Typical LNG Value Chain Development Costs

EXPLORATION & PRODUCTION	LIQUEFACTION	SHIPPING	REGASIFICATION & STORAGE
$0.5-$1.0/MMBtu	$0.8-$1.20/MMBtu	$0.4-$1.0/MMBtu	$0.3-$0.5/MMBtu

TOTAL = $3.7-7.8 billion, or $2.00 - $3.70/MMBtu

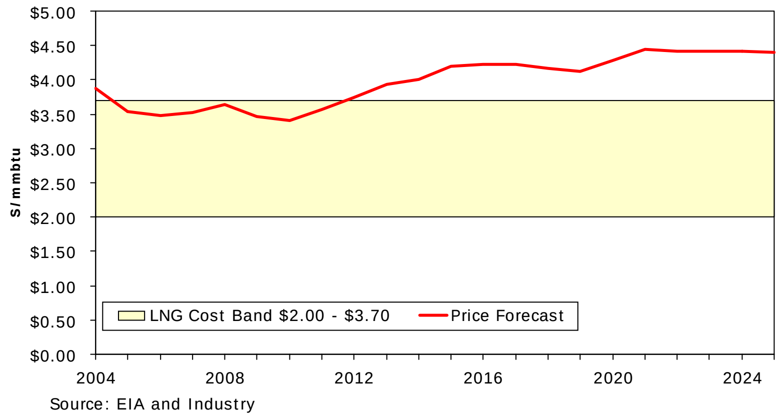
Sources: BP, ALNG, CMS and other industry information and trade publications.

Figure 25 shows the projected U.S. EIA wellhead price[40] as a line and the $2.00-3.70/MMBtu cost range for delivery of LNG to the U.S. based on the estimates in Figure 24. Clearly, LNG projects can be commercially viable and provide cost-competitive natural gas supplies to the U.S. market. The benchmark Henry Hub natural gas price has been above $3.50 per MMBTU since about the middle of 2002, with go-forward expectations of prices above $4.00 for some time to come.

---

39 For more details on LNG value chain development and costs, see CEE *Introduction to LNG* and other resource links on the CEE web site, www.beg.utexas.edu/energyecon/lng.
40 See U.S. EIA AEO 2004, http://www.eia.doe.gov/oiaf/aeo/index.html, assumptions and documentation.

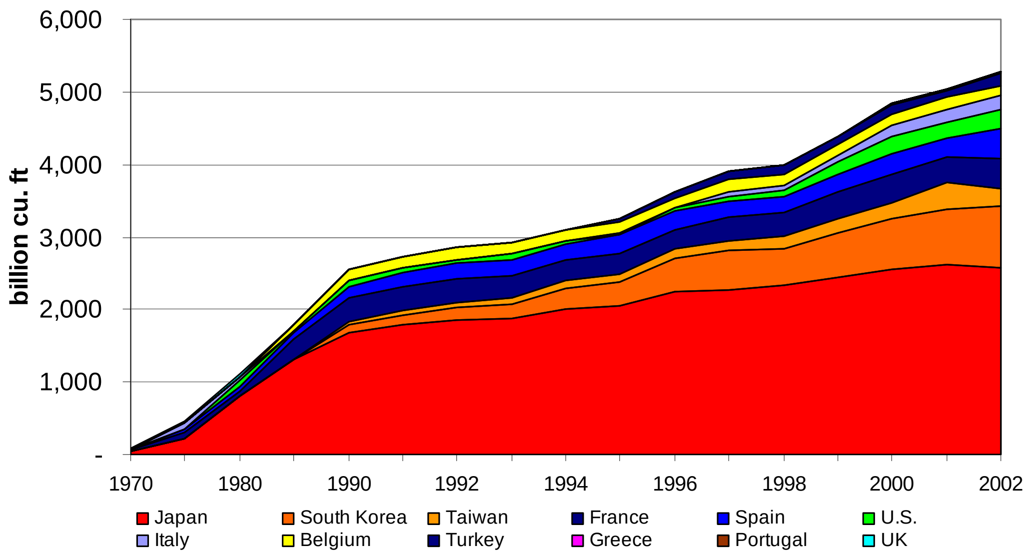
Figure 25. Natural Gas Price Forecast and LNG Development Cost ($/MMBTU)



Global LNG Demand and Supply

North America is not the only region where LNG figures prominently. Figure 26 shows strong growth in LNG demand in many countries since the first cargoes were delivered in 1964 from Algeria to the United Kingdom and France; and from Alaska to Japan. LNG demand expanded in the 1970s with shipments from Libya to Spain and Italy, from Algeria to the United States and, most importantly, from Indonesia, Brunei and the Middle East to Japan. During the 1980s, LNG trade contracted in the face of the U.S. natural gas price collapse and the expansion of exported pipeline gas supplies for continental Europe. During the 1990s, while there was some growth in the U.S. and European markets, imports to Japan and South Korea expanded rapidly. Overall, global LNG demand grew by an average of six percent annually between 1992 and 2002 (Figure 26). This trend is expected to continue.

Figure 26. Growth in LNG Demand



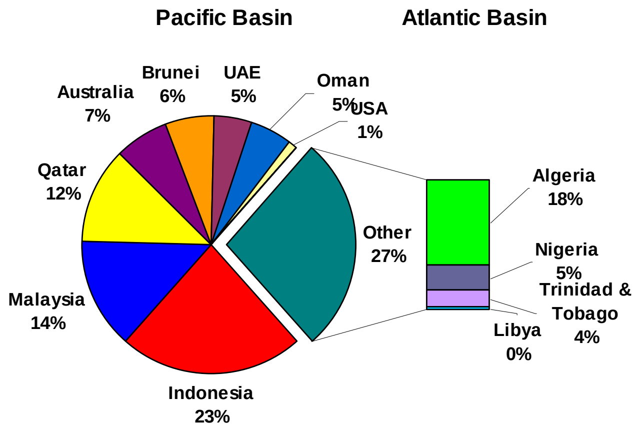
Source: Cedigaz, BP Statistical Review of World Energy June 2003

As of January 2004, worldwide proved natural gas resources were about 6,100 Tcf.[41] With respect to LNG supply, a number of producing countries host liquefaction facilities. Figure 27 shows the existing major exporters of LNG in 2002. Qatar became a significant supplier only in the late 1990s. Other Persian Gulf producers such as Abu Dhabi and Oman seem to be committed to growing their natural gas exports. Additions to export capacity are planned or underway by many current exporters (e.g., Australia, Algeria, Nigeria, Trinidad & Tobago, and Qatar). New facilities also are already under construction, planned or under discussion in locations as diverse as Norway, Angola, Equatorial Guinea, Peru, Bolivia, Egypt, Venezuela and Russia. Because LNG exports can create value from natural gas resources that would otherwise have no market outlets, it is not surprising that many gas-rich countries are exploring options for LNG exports as well as for building LNG facilities to serve their domestic needs.

---

[41] *Oil & Gas Journal*, http://ogj.pennnet.com/.

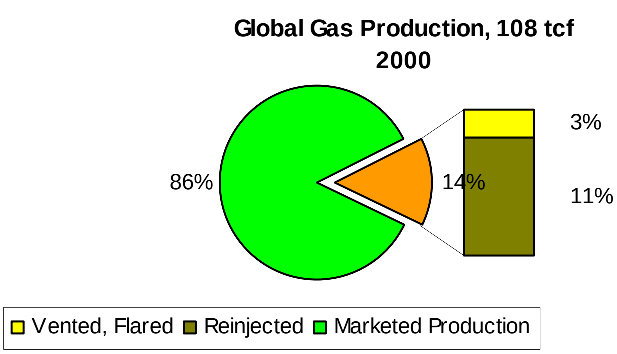
Figure 27. Global LNG Exporters, 2002



Source: BP Statistical Review of World Energy June 2003

Global Gas Production and Gas Flaring Reduction

Figure 28. Global Gas Flared



Source: U.S. EIA

At crude-oil wellheads throughout the world, producers consistently "flare" the natural gas they extract because they are a) unable (or unwilling) to re-inject gas into the reservoir, b) have no cost-effective means of transporting the gas to market via pipeline; or c) operate in areas with little or no local-market demand for natural gas. LNG could play a prominent role in reducing the wastefulness and environmental impacts of flaring, and the issue is under review by producing countries and companies, environmental groups and institutions such as the World Bank. Figure 28 indicates that about 3 percent (3.2 Tcf) of natural gas is flared annually out of the 14 percent (15 Tcf) of gas produced globally but not marketed. (The balance of this production is re-injected into the reservoir due to lack of markets.[42]) In underdeveloped countries such as Nigeria, for example,

---

[42] EIA, *International Energy Annual 2001,* http://www.eia.doe.gov/emeu/international/gas.html#Vented

taking gas that would otherwise be flared and processing it into LNG supplies for export could add an important increment of new revenue to be used for sustainable development.

Timing of New LNG Import Facilities

Matching development of LNG supplies with development of new import receiving and regasification capacity could dictate the course of natural gas prices in North America. LNG project developers understandably want to avoid building excess capacity. LNG projects are expensive, and many will be heavily capitalized. Unused capacity would weigh heavily on the financial performance of any company caught in that situation. However, a shortage of capacity relative to growth in natural gas demand would weigh heavily on the economies and customers in North America, especially in the United States and Mexico. Using current information regarding all new import projects that have been approved (including expansions at existing facilities), as well as announced projects either planned and proposed at the time this report was written, Figure 29 and Figure 30 illustrate two potential scenarios of over- and underdevelopment. (The U.S. EIA forecast for natural gas imports is used along with the number of new LNG import projects assumed in the NPC's "balanced future" outlook.) Clearly, the case illustrated in Figure 29 represents unsustainable conditions for the natural gas industry and is unlikely to occur. Just as problematic, however, are the economic impacts and outcomes associated with the scenario outlined in Figure 30. In this hypothesis, upward pressure on natural gas prices would persist unless usage could be sharply curtailed or alternate fuel sources quickly developed.

Figure 29. Unsustainable Development: Excess LNG Import Capacity If All Known Projects are Developed

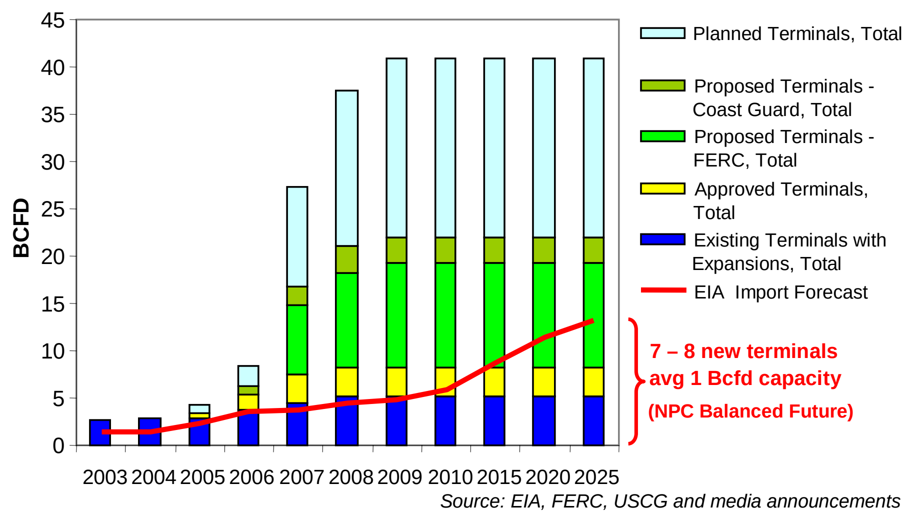
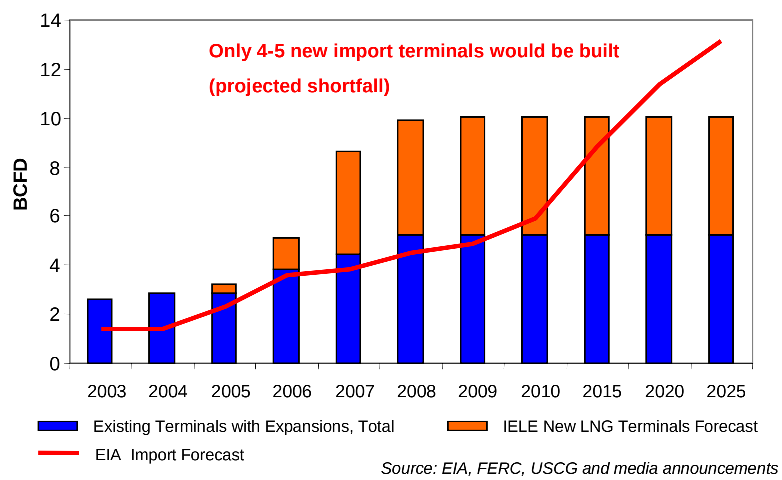


Figure 30. Impact of Inadequate LNG Import Capacity Development



Conclusions

Fact #1: North America has abundant natural gas resources. Fact #2: Domestic production of natural gas in Canada, the United States and Mexico will continue to satisfy the bulk of natural gas demand for the next two to three decades. Fact #3: Unless new supplies of natural gas can be developed and delivered to answer expected increases in demand, the countries of North America can expect continued price volatility and the economic impacts they provoke.

Alternative sources of natural gas production can be developed, and pipeline systems can be built to transport these new supplies to the North American marketplace. But new supplies are in ever more remote locations – the far northern reaches of Canada, below the deep waters of the Gulf of Mexico, and beyond the permafrost zone in Alaska. The investment requirements, technology, industry management and policy and regulatory regimes to realize new natural gas supplies from these challenging locations are considerable, and the timing surrounding them is uncertain. Expanding the amount of LNG used will also take time, money, technology and clear policy and regulatory approaches. ***A thorough review of current trends and prospective outlooks suggests that North America will need new natural gas supplies from a diverse array of sources, and that LNG represents a critical component of the overall natural gas supply of the United States.*** Above all, efficient, environmentally responsible natural gas resource development and use, with price information transmitted through open, competitive and transparent markets, is critical to North American supply-demand balances and continued energy security.

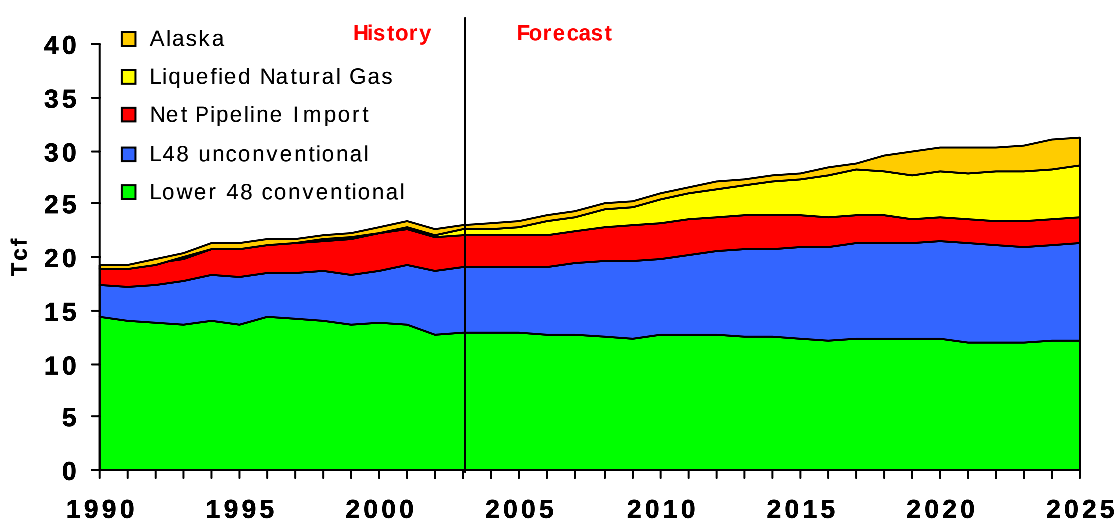
Appendix 1: Supporting Information on North American Natural Gas Supply-Demand Issues

U.S. Natural Gas Supplies – Factors and Trends

As shown in Figure 31 below, there are basically five sources for increasing natural gas supply in order to meet growing U.S. demand:

- Production from conventional resources (i.e., onshore and offshore natural gas fields and oil fields that produce associated gas);
- Production from unconventional resources (e.g., coalbed methane, gas shales and tight sands);
- Pipeline imports from Canada and Mexico;
- LNG imports from a wide variety of producing regions around the world, including Latin America/Caribbean, Middle East, North Africa, West Africa, Southeast Asia and Russia; and
- Alaskan production. Although Alaskan natural gas is domestic conventional production, before reaching the Lower 48 it will either have to be transported via a pipeline across Canada or shipped as LNG.

Figure 31. Sources of Natural Gas Supply (Tcf)[43]

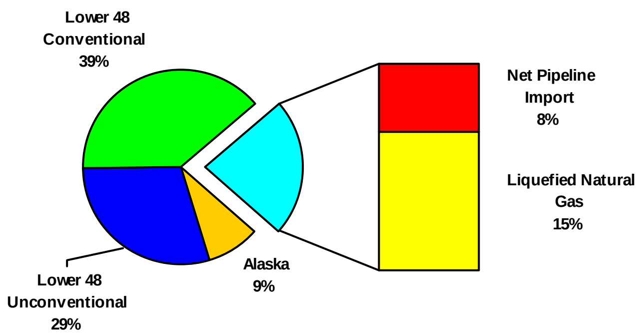


Source: U.S. EIA AEO 2004

---

[43] See U.S. EIA AEO 2004 for assumptions behind this supply outlook, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2004).pdf.

Figure 32. U.S. Supply Sources - 2025



Source: U.S. EIA AEO 2004

Figure 32 at left shows that at the end of the forecast period, U.S. Lower 48 unconventional natural gas production is expected to provide 29 percent of natural gas supply in the U.S., or 9 Tcf. Lower 48 conventional production, both onshore and offshore, is expected to continue to decline and would provide only 39 percent of the total supply in 2025. Alaskan production is expected to contribute 9 percent. LNG imports and net pipeline imports could provide 15 percent and 8 percent, or about 4.8 Tcf and 2.44 Tcf respectively.

Domestic Natural Gas Production

Domestic production is a key part of natural gas supply. In 2002, roughly 83 percent of natural gas used is produced from domestic oil and gas wells with imports making up the remaining 17 percent of domestic supply. Lower 48 producers face several challenges which include access to resources in different regions, declining production per well in traditional producing areas, and attracting timely and sufficient capital to the industry.

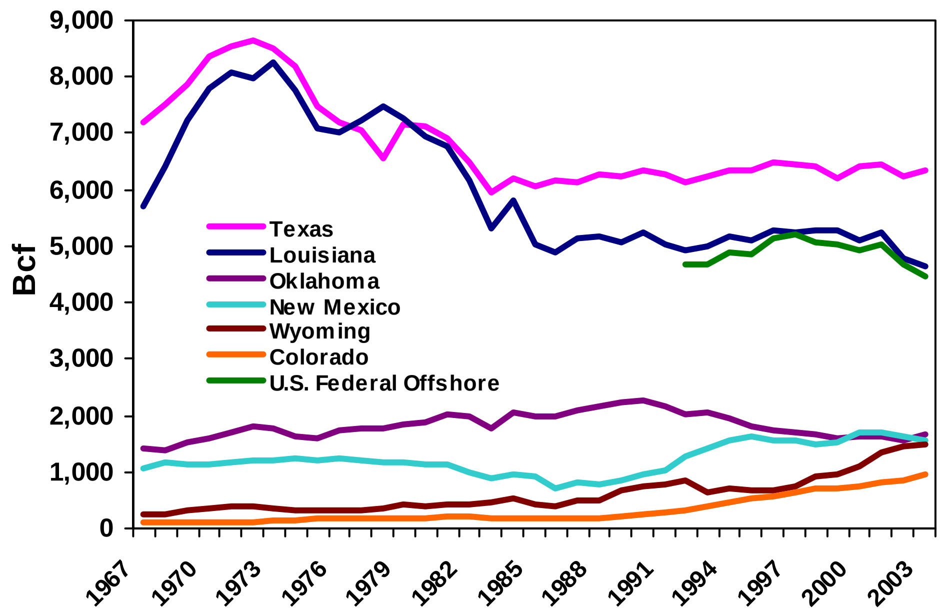
Resource Base

In 2002 the U.S. EIA estimated the total amount of technically recoverable resources to be 1,431 Tcf.[44] The U.S. proved reserves of natural gas totaled 187 Tcf as of year-end 2003 or roughly equal to nine years of natural gas use at 2002 consumption levels.[45] A few states are the source of the majority of the natural gas reserves and production within the United States. The major producing areas include Texas, Louisiana, the Gulf of Mexico federal offshore, New Mexico,

[44] EIA - http://www.eia.doe.gov/emeu/aer/pdf/pages/sec4_3.pdf
[45] Oil & Gas Journal, Worldwide look at Reserves and Production 2003, http://ogj.pennnet.com/

Oklahoma, Colorado, and Wyoming, accounting for 78 percent of reserves and 83 percent of production. For 2001 and 2002 these same areas, and in particular Texas, Wyoming, and Colorado accounted for all of the increases in proved gas reserves according to the U.S. EIA.[46] Figure 33 below shows production trends for the key states and U.S. federal offshore (Gulf of Mexico; Texas and Louisiana with small volumes offshore Alabama) as a separate item for comparison to Texas and Louisiana, both of which include federal offshore production as well as production in state waters in the state totals. Increases in production for New Mexico, Wyoming and Colorado include development of unconventional resources (see later section). The large producing states of Texas, Louisiana and Oklahoma demonstrate the maturity of Lower 48 producing basins and challenge associated with maintaining Lower 48 onshore supplies. But the state level data also demonstrate what could be done to increase domestic production with new policy and technology approaches, in particular for abundant unconventional resources.

Figure 33. Production Trends for Leading States and Federal Offshore

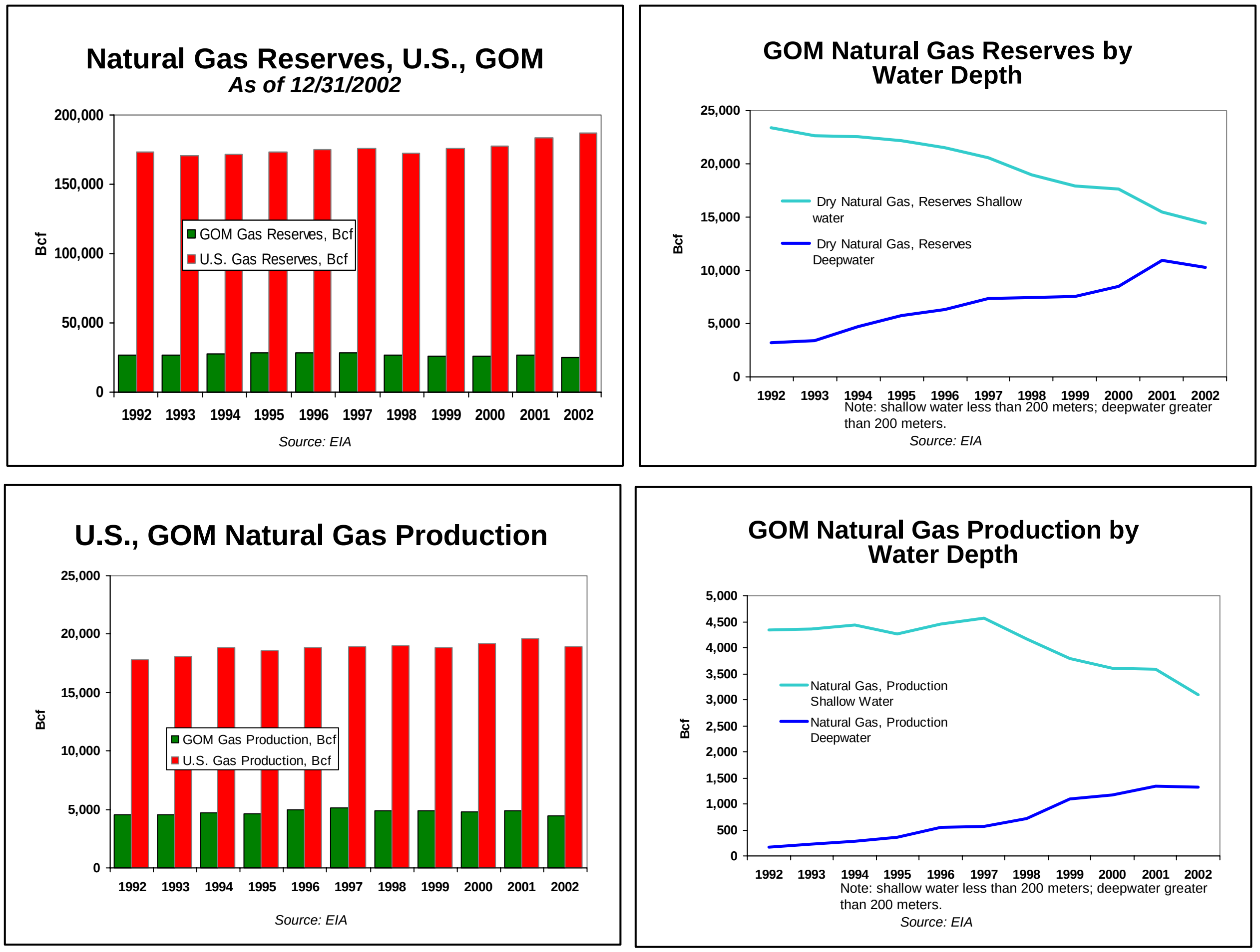


Source: U.S. EIA and State Agencies

[46] Those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The potential of the deeper waters in the U.S. Gulf of Mexico (GOM) to offset production declines in shallower waters is shown in Figure 34 below. However, it will take time to expand and stabilize deep water natural gas deliveries.

Figure 34. U.S. Gulf of Mexico Deep Water Trends



As sustained production flows are established for the deeper waters, and as pipeline or other transportation systems to support these flows are developed, these new plays will make a more substantial contribution to the U.S. natural gas supply base. Importantly, upwards of 75 percent of domestic production comes from onshore fields. Sustaining the vital component of onshore production and extending onshore production though the addition of unconventional resources while also pursuing prospective areas offshore are some of the industry's main targets.

Unconventional Domestic Natural Gas

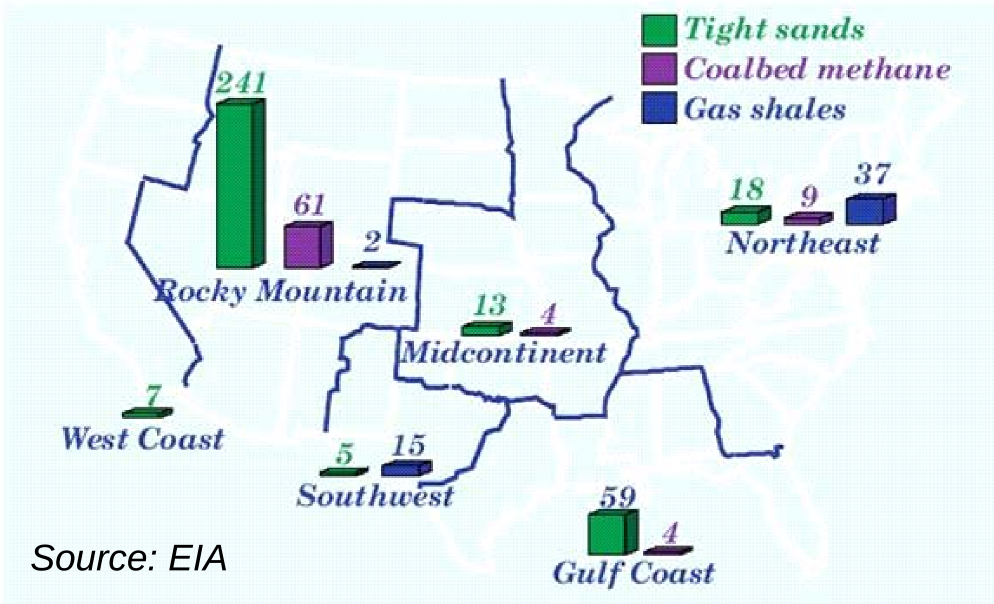
Capital spending cycles for natural gas producers apply to unconventional natural gas resources as well. In addition, higher costs of production of unconventional resources may render fundraising for these projects more difficult.

Unconventional gas resources include natural gas extracted from coalbeds (coalbed methane or CBM, sometimes referred to as coal seam gas) and from low permeability sandstone and shale formations, tight sands and gas shales (Figure 35). Most of the subsurface reservoirs containing these resources must be subjected to a significant degree of stimulation (e.g., hydraulic fracturing) to attain sufficient levels of production to be economic. Total unconventional gas production increased from about 3.0 trillion cubic feet or 17 percent of total natural gas production in 1990 to 5.9 trillion cubic feet or 32 percent of total production in 2002 (see previous Figure 31). Unconventional natural gas has become an increasingly important component of total lower 48 production over the past decade. It is expected to constitute approximately one-third of U.S. natural gas production by 2025 (see previous Figure 32). Unconventional resources cost more to produce when compared to conventional natural gas resources. According to a U.S. EIA report, the average coalbed methane well under 2000 feet had average annual operating costs of $108,100 vs. $21,900 for conventional natural gas wells of the same depth.[47] Industry experts have reaffirmed that, "Going forward, most of the gas that we'll find in this country onshore will be 'unconventional' - tight sands gas, shale, and coalbed methane - gas that is higher cost and lower margin."[48]

---

[47] U.S. EIA, *Oil and Gas Lease Equipment and Operating Costs 1986 through 2002*, 2002. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.html.
[48] Richard Sharples, Anadarko Petroleum Corporation, Prepared Witness Testimony "The Committee on Energy and Commerce" United States House, http://energycommerce.house.gov/108/Hearings/06102003hearing944/Sharples1519print.htm.

Figure 35. Unconventional Gas Undeveloped Resources by Region as of January 1, 2002 (trillion cubic feet)



In view of the generally higher cost associated with unconventional natural gas, tax incentives designed to encourage development were successfully implemented in the late 1980s and early 1990s which boosted exploration of the resources. However, mitigating some of the higher costs for unconventional production are tax credits, which, when available, lower the net costs of production. According to the U.S. EIA, the alternative fuels production tax credit, largely used to develop coal bed methane and tight sands gave the natural gas industry over $1.0 billion in savings in 1999.[49] Since then, the technologies developed and advanced in pursuit of these resources have contributed to continued growth in production in the absence of the tax incentives. Indeed, increasing production from unconventional gas resources has actually offset a decline in conventional gas production in recent years.

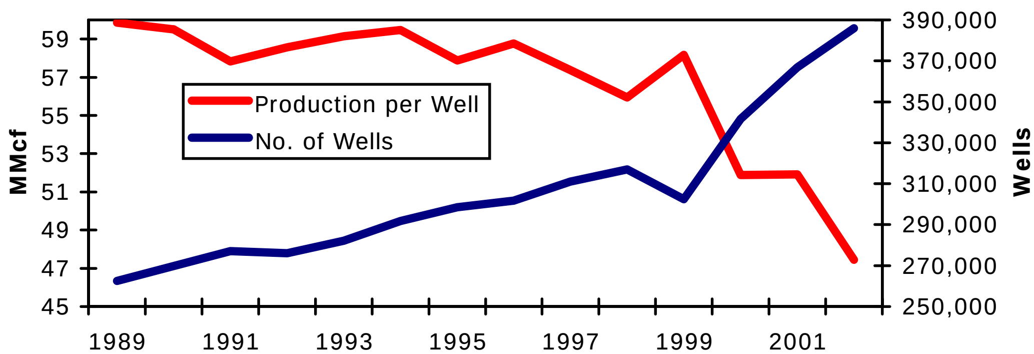
Production Challenges

As shown in the aggregate state data, the U.S. is experiencing both depletion and steep decline curves in established fields, and also lower rates of productivity in new gas wells. The rate of decline for natural gas wells has increased from 16

[49] U.S. EIA, *Federal Financial Interventions and Subsidies in Energy Markets 1999*.

percent to 28 percent between 1990 and 2000.[50] Figure 36 shows the decline in U.S. average production per well while the number of gas wells increased from 1989 to 2001. In 1989, roughly 262,000 gas and gas condensate wells produced 60 million cubic feet (MMcf) a year. In 2001, almost 367,000 wells (40 percent more than in 1989) were producing at a rate of 52 MMcf a year, or 13 percent less than in 1989. Average natural gas well productivity declined significantly after reaching a peak of 160 MMcf in 1970 but was stable around 60 MMcf since the early 1980s (productivity varies by field and basin; with more complex reservoirs, productivity also can vary considerably within fields and basins). The recent decline is even more significant when seen from this historical perspective. Several reasons underlie the trend toward declining well productivity: an increase in "infill" drilling (drilling new wells between existing ones) as well as drilling to extend established, mature fields; a shift toward different kinds of prospects (such as unconventional reservoirs); and general maturity of the U.S. resource base.

Figure 36. U.S. Average Gas Well Productivity (MMcf)



Source: U.S. EIA

Given the overall trend in natural gas well productivity, a central question is whether new drilling will yield gas production at rates equivalent to historical patterns. Indications are that productivity for new onshore natural gas wells may not reflect past rates of production. An often referenced phenomenon is the "treadmill" in which new natural gas drilling and production barely offsets natural depletion and declines (especially true for "fast gas" reservoirs, such as the shallow

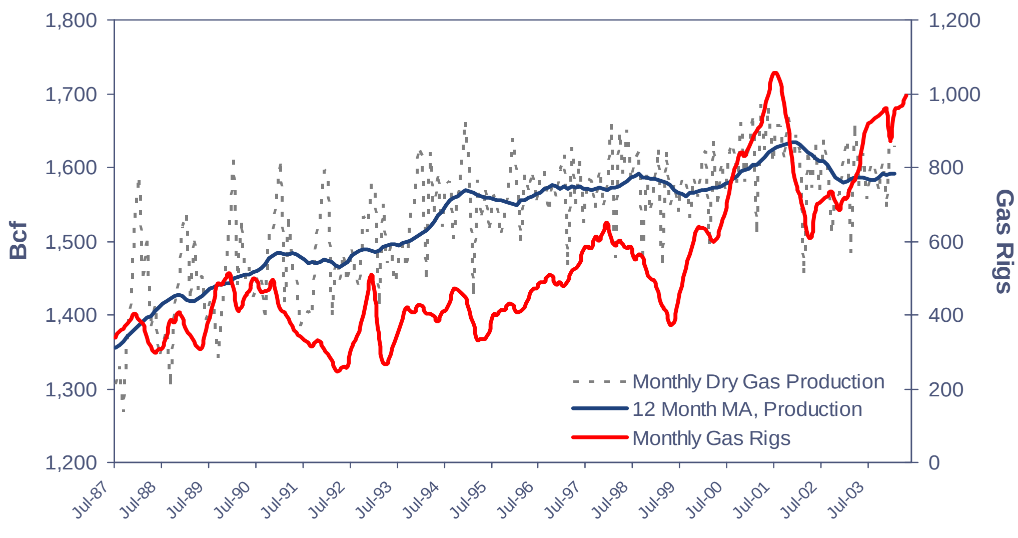
---

50 Independent Petroleum Association of America (IPAA), *Natural Gas: Can We Produce Enough?* http://www.ipaa.org/govtrelations/factsheets/NaturalGasProdEnough.asp.

water, continental shelf of the U.S. Gulf of Mexico). The acceleration of field production declines in the U.S. could also be the logical outcome of advanced production technologies. In particular, horizontal drilling, which allows faster recovery rates from horizontal well bores; new techniques for treating (fracturing) reservoirs; and advanced seismic that increases the efficiency of field development are thought to contribute heavily to steeper decline curves for new natural gas wells and fields. Technology makes it possible for companies to supply more natural gas sooner to meet growing demand while also yielding quicker and higher returns on their investments.

Another factor impacting U.S. production is the lag between drilling activity and delivery of new supplies, as shown in Figure 37 below. If at least current levels in average gas well productivity are achieved, then the acceleration in drilling since 2002 will yield new supplies which will help to ease the U.S. supply-demand balance. If not, then pressure on the supply side will continue to build. Only about three percent of all successful crude oil and natural gas wells drilled are exploration wells for new, untested natural gas prospects.

Figure 37. U.S. Natural Gas Production vs. Rig Count



Source: U.S. EIA, Baker Hughes

The cost of equipment and operations for a natural gas well increases with depth (keeping the rate of production constant).[51] Costs are also higher for offshore wells. With declining well productivity and faster depletion, an increasing number of wells need to be drilled to sustain current production levels, and even more to increase production. Moreover, many new wells will be deeper and offshore. Clearly, the total cost of producing natural gas will rise under these circumstances.

Timing of Capital Expenditures and Production

Sources of capital for natural gas supply development and associated infrastructure are derived from industry cash flows and a broad, diverse assortment of external sources including commercial banks, investment houses that can mobilize funding through capital markets, and equity providers which can range from "friends and family" for small producers to large institutional investors like pension funds and insurance companies. All capital investments, including those made by industry, are subject to profitability – rates of return – that in turn are driven by many factors, among which natural gas (and oil) prices are critical.

In order to drill a significant number of new wells, much less maintain current levels of drilling, the industry will have to invest capital. According to the Independent Petroleum Association of America (IPAA), between 1999 and 2015 the natural gas industry will have to spend $40 billion a year - an increase of $10 billion a year more than is currently being spent. The IPAA further estimated that to meet future demand, "The industry must raise an estimated $658 billion, create a workforce capable of drilling the wells, and build the rigs necessary to increase annual drilling rates from 24,000 to 37,000 wells by 2010 and to as high as 48,000 by 2015."[52]

Sustaining capital investment in an industry characterized by sharp commodity price cycles is always difficult. When natural gas prices are low, capital is re-directed toward industries that provide better returns, contributing to or

---

[51] U.S. EIA *Oil and Gas Lease Equipment and Operating Costs 1986 Through 2002.* http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.html
[52] Independent Petroleum Association of America (IPAA), *Natural Gas: Can We Produce Enough?* http://www.ipaa.org/govtrelations/factsheets/NaturalGasProdEnough.asp

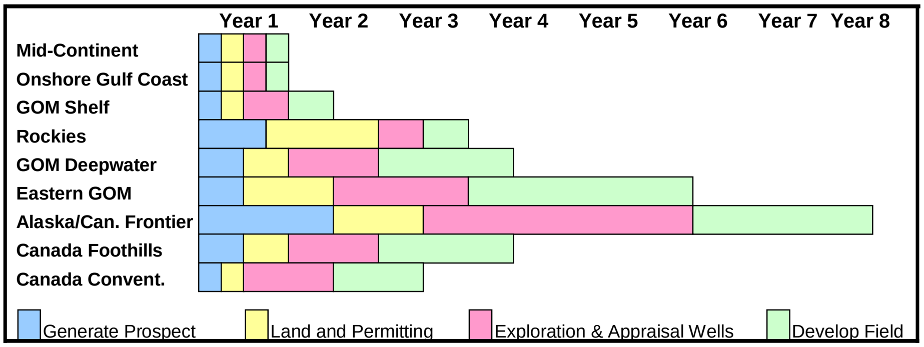
exacerbating supply-demand imbalances when natural gas market conditions are more robust. One expert estimated that, as of 2002, the value of the natural gas industry was less than that of all the cash that has been invested in it and that the industry was valued at just 73 percent of the cash invested without the largest international companies (95 percent with the largest companies included). The upstream (E&P) sector earned a 5.6 percent return on assets on average between 1999 and 2002 while the midstream (pipelines, storage and other facilities) earned roughly a 2.4 percent return on assets, "considerably below the 5.0 percent returns earned by the broader S&P 500 index [excluding the financial sector] during the second half of the 1990s." A conclusion was that "a combination of regulation, taxes and direct market intervention have made the return on capital in the energy industry a breakeven proposition at best and have made investing in…transportation, storage and other aspects of the infrastructure…distinctly unprofitable. The market has responded by not providing the capital to expand, and the net result is the capacity constraints that you see today."[53] High oil and natural gas prices have improved capital flows and returns since 2002; a key question for investors is what to expect with regard to long run prices and profitability for the industry going forward.

A factor affecting capital flows into the natural gas E&P industry is availability of "good" projects that can provide reasonable returns on investment across a range of natural gas prices. E&P projects require lead times, some of which are lengthy (Figure 38 below). This means that projects must survive low price periods if they are to reach full development. For major new areas of E&P activity – like the Alaska/Canada frontiers and GOM deep water – this means huge risks for the industry and capital providers. To sustain large projects like these through low price periods requires careful financial management and operating practices. Long lead times to production and delays or disruptions related to unfavorable commodity prices introduce the added risk that market fundamentals may shift against large projects by the time production comes on stream.

---

[53] All information from testimony to the House Resources Committee, U.S. Congress, by Dr. Jeffrey Currie, Senior Energy Economist at Goldman Sachs, June 10, 2003, http://energycommerce.house.gov/108/Hearings/06102003hearing944/Currie1524.htm.

Figure 38. Typical Lead Times for E&P Projects



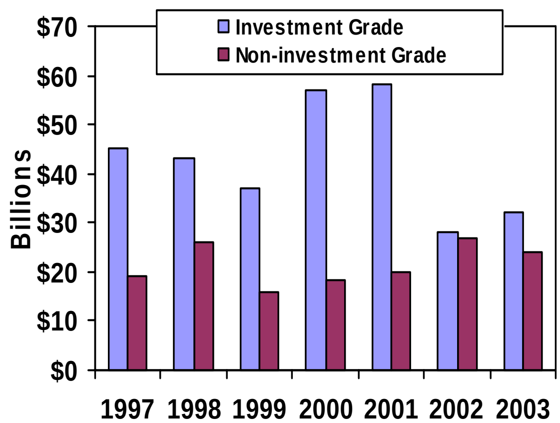
Source: Anadarko Petroleum Company

If producers lack confidence with regard to potential returns, they will not venture into marginal projects with higher costs. (Similar constraints impact investment in midstream assets.) The E&P industry has responded to long term price cycles and shorter term price volatility by consolidating, reducing costs (including application of new technologies and improving asset management practices) and employing risk management. A common form of risk management is a "natural hedge" in which capital budgets are reduced when commodity prices are not favorable for E&P investment and targeted returns. This means constant pressure on E&P projects to compete with other investment opportunities (and for domestic E&P projects to compete with those outside of the U.S. and North America that may provide better returns). These are long-term trends that have been in place since the oil and natural gas market disruptions of the 1970s.

A recent event impacting U.S. and, to some extent, Canadian natural gas upstream (and midstream) finance was the loss of capital provided for energy sector investment by energy merchants – unregulated affiliates of energy companies, many of which are utilities, that are largely engaged in energy trading and risk management and investment in unregulated assets like independent electric power generation. Financial collapse in that sector between 2001 and 2002 resulted in credit downgrades and write downs for many energy merchants, forcing them to shutter many operations, including, in some cases, E&P finance. Companies that were impacted included Aquila, Duke Capital Partners, El Paso Energy, Enron, and

Mirant.[54] By most accounts, much of the financing being made available to producers by the energy merchants was directed toward higher risk projects that produced poor returns.

Figure 39. Oil and Gas Lending[55]



Source: Loan Pricing Corp.

In many cases, however, they provided crucial funding to exploit proven, undeveloped natural gas reserves. Fresh capital is being attracted back into E&P albeit at a slow pace as new sources emerge with stronger criteria for asset quality and as energy credit transactions increase for all energy sector activities (see Figure 39 at left).[56]

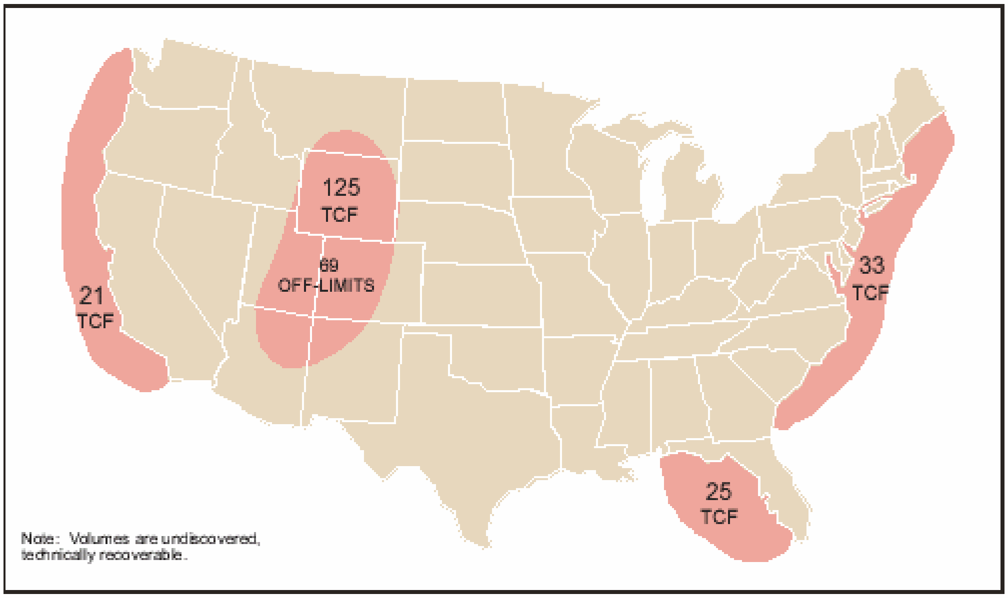
Access to Resources

Natural gas exploration and development is not possible across the entire resource base. A key condition is "access" – the ability for energy companies to lease surface land and subsurface minerals, including both private and public (federal and state) for E&P operations. This includes not only drilling, but access to surface lands for roads and other critical activities, to sources of water for drilling and production operations, rights of way for pipelines, and so on. Some federal and state lands and offshore areas are not open to drilling. It is estimated that over 50 percent of technically recoverable resources are under federal lands. In Figure 40, taken from the 2003 NPC study, resource estimates are provided for four major areas in the Lower 48 where E&P operations are restricted. About 215 Tcf of the resource base is currently not open to exploration.

---

[54] For example, see "Oil and gas companies' capital supply and capital demand constrained in 2002" by Paula Dittrick, *Oil & Gas Journal*, March 7, 2002.
[55] Includes E&P, oil field services, refining, integrated oil companies, pipelines. From "Big Deals," in *Here's the Money: Capital Formation in 2004*, Oil and Gas Investor, May 2004
[56] Based on CEE's own ongoing survey of producer finance conditions and capital providers, and consensus within the IPAA Supply-Demand Committee of which CEE is a member. Also see various articles in *Here's the Money: Capital Formation in 2004*, Oil and Gas Investor, May 2004.

Figure 40. Lower 48 Technical Resource Impacted By Access Restrictions



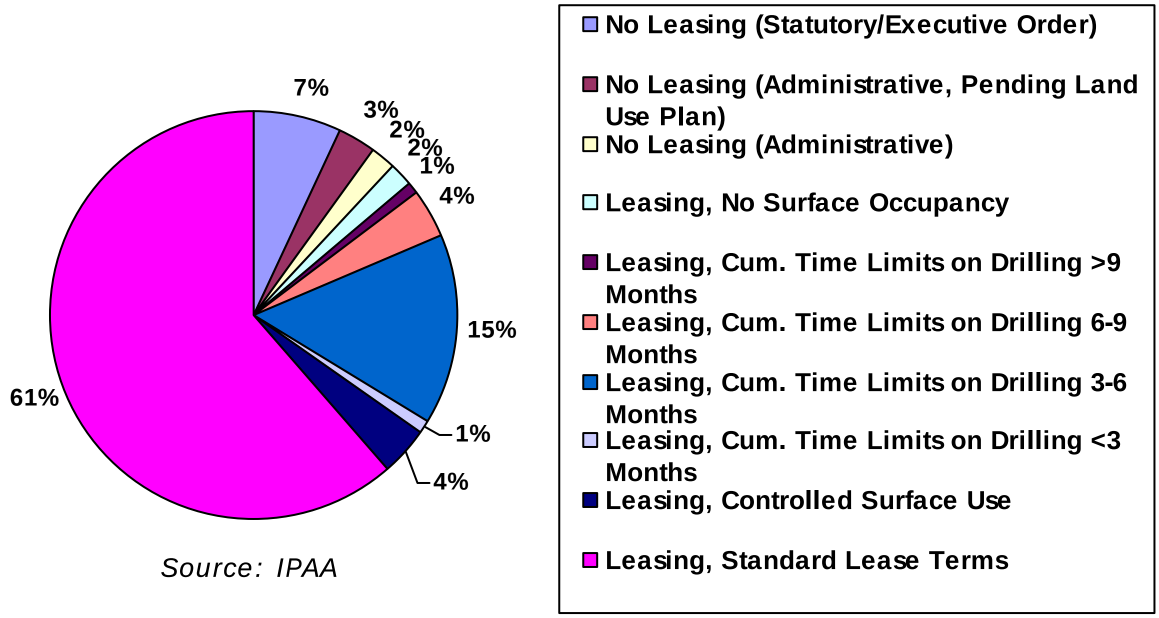
Source: NPC

Unconventional natural gas resources face the same constraints that conventional natural gas resources do when it comes to the area being open for exploration and development of natural gas resources. If one compares Figure 40 and Figure 35, it is clear that the bulk of the unconventional gas resource base is located within the Rocky Mountains where there are restrictions on access for E&P activities.

Restrictions on access can take many forms. A 2003 U.S. Department of Interior study illustrated the ways in which E&P operations can be limited, as shown in Figure 41 below.[57] When Figure 41 is compared with Figure 38 on E&P lead times, the dilemma for new natural gas supply development, at least in the Western U.S., becomes clear.

[57] See IPAA, www.ipaa.org, for details on the U.S. DOI study.

Figure 41. Limitations on Natural Gas Development Access in the U.S. Intermountain West



Source: IPAA

Access is also impacted by land management practices maintained by federal and state agencies. These include record keeping, ability to track performance by leaseholders, loopholes that enable speculators to hold leases that they have no intention of drilling – all have bearing on how easy or difficult it is to launch new E&P activities.

Apart from public lands, access to private lands for E&P activity may also be restricted. Private land and mineral owners may choose not to host oil and gas industry activity. Private lands turn over as part of estates or land transactions; large blocks of private lands prospective for drilling may be broken into smaller lots (increasing the cost and difficulty of obtaining leases for E&P operations), or dedicated to other uses such as wildlife preserves.[58] Urbanization and suburban expansion as well as growth in recreational housing and development in areas that are prospective for oil and gas development also impact access.

---

[58] The Texas A&M Real Estate Research Center reports on private land holdings and transactions each year, and serves as an indicator of the extent to which changes in private land ownership impacts access for oil and gas development. See http://recenter.tamu.edu/, quarterly reports on *Texas Land Market Developments*.

Alaska Production

Alaska has substantial quantities of natural gas with 8.5 Tcf of proved natural gas reserves as of 2002[59] and a technically recoverable natural gas resource estimate of 252 Tcf as of 2002.[60,61] Alaska is not connected via natural gas pipeline with the rest of the United States, although the state does have an LNG facility which ships LNG primarily to Japan. Alaska produces about 3.5 Tcf of natural gas annually, mainly associated and dissolved gas produced along with crude oil. Most of the gas produced, 3.0 Tcf, is on the North Slope and injected back into the reservoirs because of lack of market access.[62] The state additionally may have substantial unconventional natural gas resources.

Currently, two prominent proposals exist for building pipelines out of Alaska – a southern route and a northern route. The southern route would have the pipeline go across Alaska into Canada at the very southern part of Alaska, paralleling the existing crude oil pipeline that originates at Prudhoe Bay on the North Slope for much of the distance. Proponents of this route argue that it would produce more jobs for Americans versus the northern route. The northern route would link up with natural gas production in northern Canada's Mackenzie Delta. For either pipeline route, Canada would serve as both a transit country and customer, taking Alaskan natural gas to supplement Canadian production for oil sands operations in northern Alberta. Many analysts believe that both pipelines would require a price of $4/MMBTU or higher for sustained periods and perhaps government support of some kind as well. (Of note is that the Canadian oil sands operations, considered to be important "anchor" customers for Alaska production, are sensitive to higher natural gas prices whether as a consequence of market dynamics or policy actions that would provide price floors to support the pipeline projects.) All energy forecasts examined for this report assume that at least one Alaska gas pipeline will be built and that natural gas development will occur within the forecast time frame

[59] U.S. EIA, http://tonto.eia.doe.gov/dnav/ng/ng_enr_sum_dcu_SAK_a.htm
[60] U.S. EIA - http://www.eia.doe.gov/emeu/aer/txt/ptb0401.html
[61] By comparison, the NPC natural gas study references 35 Tcf of discovered resource and 213 Tcf of undiscovered potential. See www.npc.org.
[62] U.S. EIA, http://tonto.eia.doe.gov/dnav/ng/ng_enp_sum_sak_a_d.htm

(typically 25 years).[63] The previous Figure 38 illustrates that any outlook on Alaska must incorporate substantial lead times for development. An alternative proposal is to build a north-to-south gas pipeline that would join with natural gas production in Cook Inlet, and where expanded liquefaction capacity would provide export options for Alaskan natural gas in the form of LNG.[64]

Supply Issues in Canada

As noted in the main body of this report, Canada may continue to figure heavily in closing the gap between natural gas production in the Lower 48 and demand in the future. But Canada faces its own production declines in mature fields.

Western Canadian Sedimentary Basin (WCSB)

Currently, 70 percent of all Canadian natural gas production occurs in the western province of Alberta and surrounding areas, which together comprise the Western Canada Sedimentary Basin. The NEB believes that the ability to produce natural gas in this region will decline in the future, with production expected to fall from 16.6 bcf a day in at the end of 2001 to 15.9 bcf a day by the end of 2004.[65]

Well depletion rates in the WCSB have been accelerating, requiring 20 percent of production to be replaced through exploration yearly according to the NEB, constituting a Canadian version of the U.S. “treadmill” (see previous section on Production Challenges). From 1996 to 2001 the number of natural gas wells drilled each year increased from 4,800 to 12,400 (almost 158 percent increase) while production only increased by about 15.8 percent, from 5.7 to 6.6 Tcf. During 2003, 13,944 natural gas wells were drilled in Canada, up considerably from 9,073 drilled during 2002 and the largest number of wells completed since 1983 (when a mere 1,581 wells were completed). Alberta and the WCSB dominate, with 11,067 wells

---

[63] The NPC study assumed that 18 Tcf of Alaskan natural gas production will be transported to market. See note 61.
[64] Action was taken in April 2004 by the Alaska legislature to establish a state fund to support a combined pipeline/LNG project. See http://gov.state.ak.us/archive.php?id=891&type=1.
[65] NEB Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin. http://www.neb.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityWCSB2003_2005_e.htm.

drilled in that province alone.[66] Like the U.S., more wells must be drilled in the WCSB to maintain current natural gas production levels. In addition, initial production flows from natural gas wells has declined, another indication of WCSB maturity. These factors underlie the NEB's conclusion that in spite of increased drilling activity, overall annual production for the WCSB could fall by approximately 250 Bcf over the short term.

Frontier Areas

Canada has a substantial amount of discovered natural gas resources, estimated to be roughly equal to their proved natural gas reserves, known but not currently accessible. Additionally, the estimated resource base of the frontier areas of Canada is not fully explored; however there are substantial resources present. According to the NEB, northern Canada contains 213 Tcf of natural gas.[67] These reserves lie in frontier areas in Canada's far north, like the Mackenzie River Delta, posing challenges for both E&P activity as well as for pipeline transport to markets.

The barriers to the recovery of discovered natural gas reserves are physical, financial and technical. The isolation of frontier natural gas resources from markets makes them less attractive for development. Currently several pipelines are proposed that could transport natural gas from the frontier areas, including proposals to link frontier production with a northern route pipeline from Alaska (as previously discussed). Distance, terrain and winter ground temperatures will complicate pipeline construction. Further, aboriginal land claims also pose a barrier beyond the usual financial issues associated with constructing a natural gas pipeline. Some of these indigenous claims have been resolved but along with environmental sensitivities the state of aboriginal lands adds complexity to E&P projects that are already high risk.

---

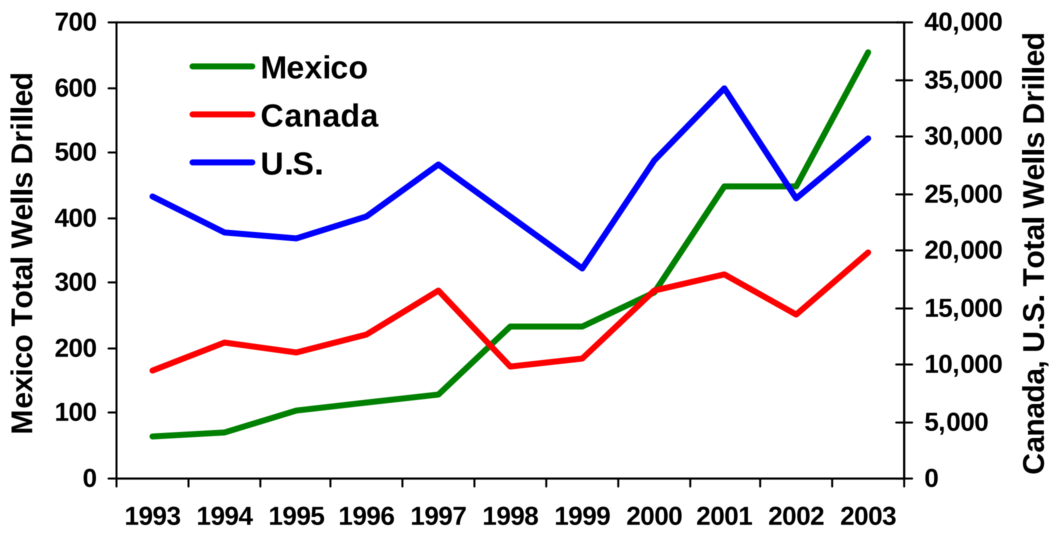
[66] Data from Canadian Association of Oilwell Drilling Contractors, http://www.caodc.ca/.
[67] National Energy Board of Canada Canada's Energy Future: Scenarios for Supply and Demand to 2025, http://www.neb-one.gc.ca/energy/SupplyDemand/2003/English/SupplyDemand2003_e.pdf Appendix P. 120

Mexico

Mexico, endowed with a large resource base, balances its growing demand for gas with shipments from the U.S. Mexico may host LNG facilities on both east and west coasts to balance its own fast growing market as well as for export to the Lower 48. But to truly participate in the North American marketplace as a net supplier, Mexico will need to make substantial changes to its state owned and controlled oil sector. By any measure, Mexico is a relatively unexplored province for oil and gas.

Figure 42 provides a snapshot of why Mexico is thought to have strong potential to boost its natural gas production by comparing total oil and gas wells drilled for all three countries in North America during 2003. Mexico's more than 600 well completions pale in comparison to Canada's roughly 20,000 or completions in the U.S. of nearly 30,000. (Of interest is the extent to which Canada has approached the U.S. in rates of drilling, a reflection of relative maturity – by contrast, in 1983 Canada drilled almost 7,000 wells to the U.S.'s roughly 76,000.)

Figure 42. Comparison of Oil and Gas Wells Drilled

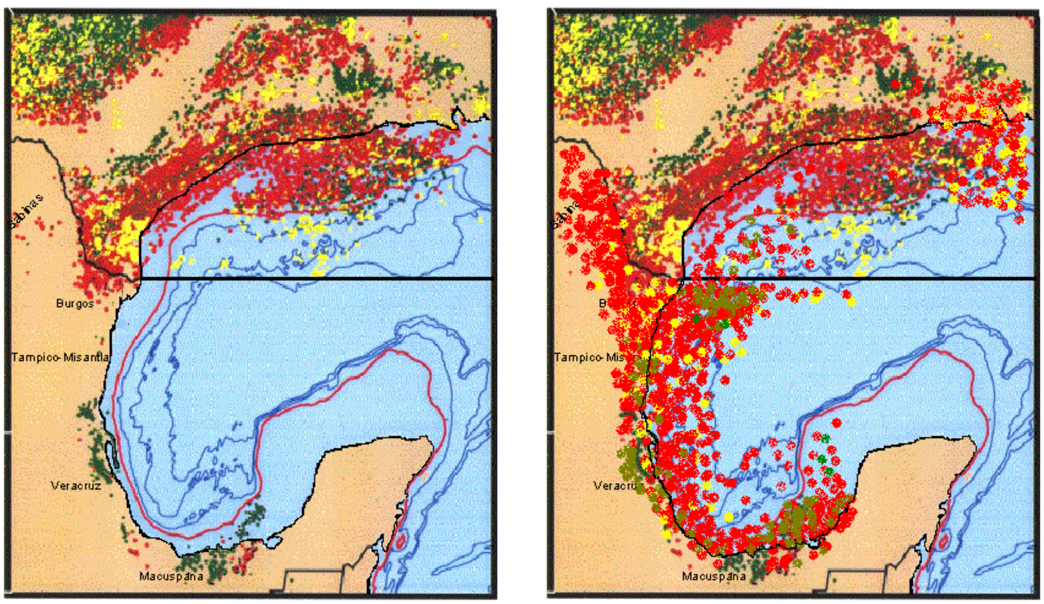


Sources: U.S. EIA, PEMEX, Canada Association of Oilwell Drilling Contractors

Between 1999 and 2003, PEMEX's capital spending increased from $4.6 billion to $9.4 billion U.S. dollars, while capital intensity per barrel increased from $3.11 to

5.93.[68] As noted in the main body of this report, meaningful policy actions must take place in order to enable upstream investment at a level that would alter not only Mexico's course but exert significant effects on North American supply-demand balances. An example of the impact of the MSC program on PEMEX's natural gas production was provided in Figure 20. Even more intriguing is a simulation of what could be achieved with private investment beyond what the MSC or a similar program could provide. Figure 43 demonstrates this projection by approximating policy reforms that would enable a similar development path to that of the U.S. Gulf of Mexico (onshore and offshore) given Mexico's oil and gas geological features across its main basins and embayments (Burgos, Tampico, Veracruz, Macuspana). (Red areas indicate natural gas producing fields.)

Figure 43. Existing Gulf of Mexico Region Nonassociated Natural Gas Development (left) and Projection with Policy Reforms in Mexico

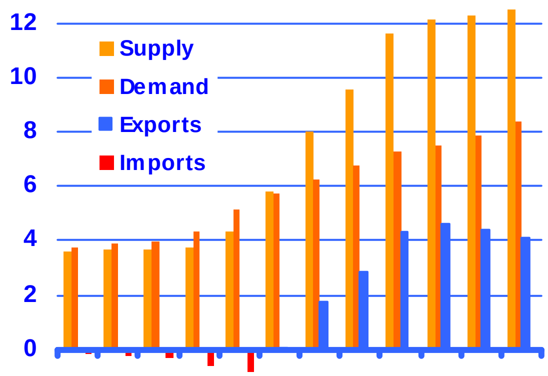


Sources: SENER; provided by Alpek Corp.

[68] See PEMEX statistical reports and annual Memoría de Labores, www.pemex.com.

With a more substantive policy approach, not only would Mexico balance its internal supply and demand for natural gas, it would become a substantial net exporter to the North American marketplace, as indicated in Figure 44 below left.

Figure 44. A Scenario for Mexican Gas

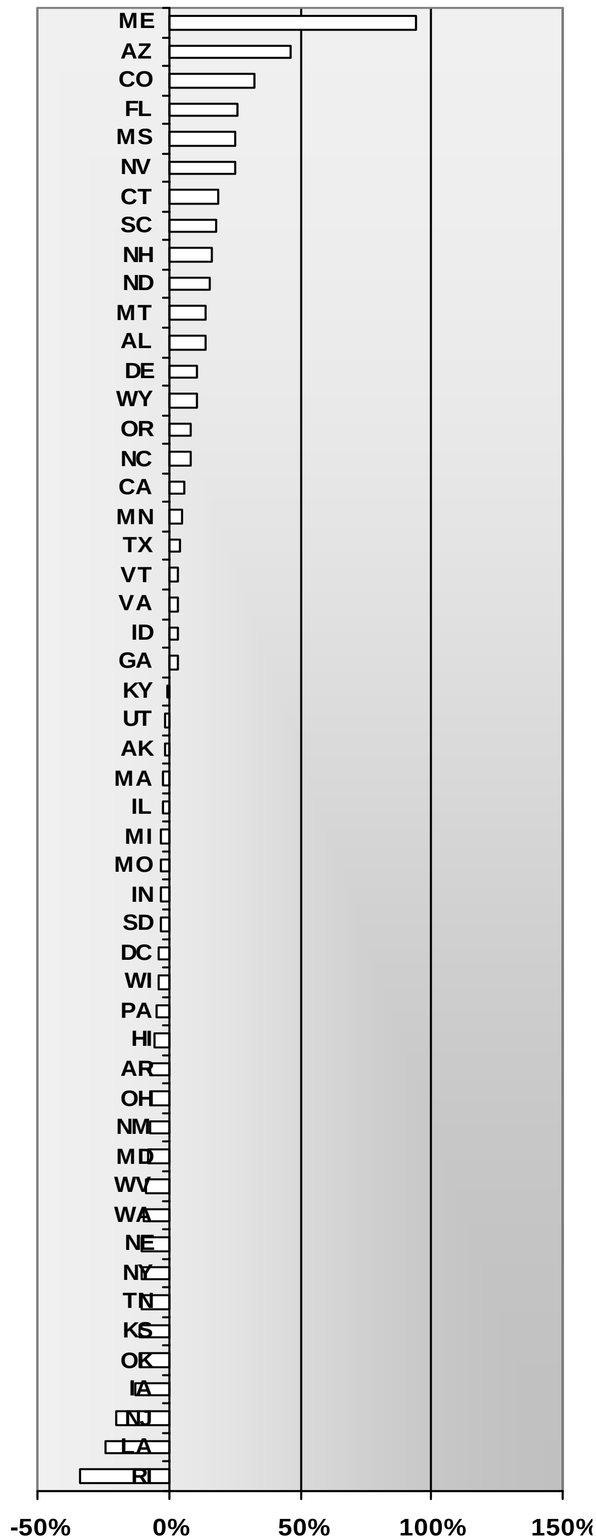


Source: SENER; provided by Alpek Corp.

Demand-Side Issues

Figure 45. Natural Gas Consumption by State, 1997-2002

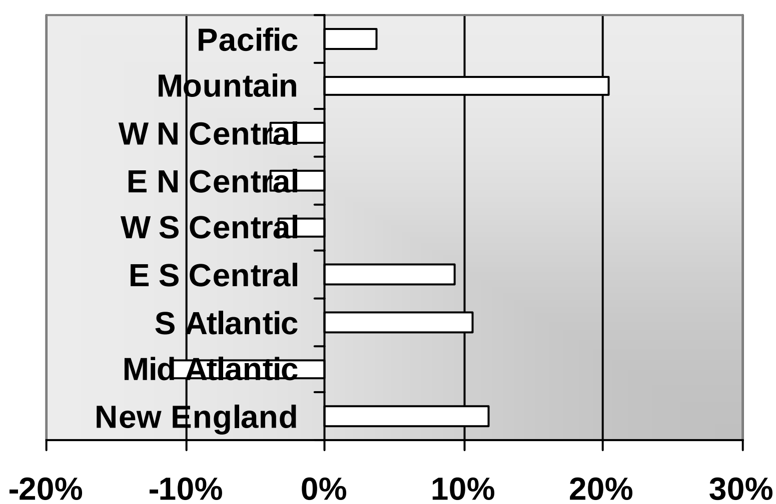
Source: U.S. EIA



While this report focuses on the large geographies of the U.S., Canada, Mexico, and North America as a whole, the North American marketplace is not monolithic. States, regions and provinces within North America have substantial variation in natural gas use, a function of regional climate and weather patterns (for example, peak use of natural gas for power generation during summertime in the southern U.S. as opposed to winter heating in New

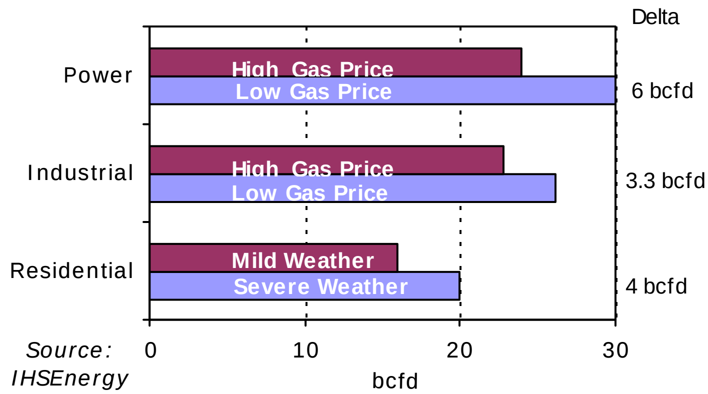
England, for example), level of economic activity and the kinds of businesses and industries that operate in different locations. In addition, some states, provinces and regions are significant exporters or importers of energy, by virtue of either resource endowments or locations relative to international exports and imports. Figure 45 (above right) and Figure 46 (left) illustrate the variability and trends in natural gas demand across the U.S. states and census regions (for a map of census regions, see Table 2 later in this appendix). Along with changes in underlying economic and demographic factors (from long term industrial shifts to economic recession during 2001-2003 to movements in population across states and regions), are those previously discussed with respect to increased use of natural gas for electric power generation. The changes in state and regional natural gas consumption generally follow the pattern of gas fired power generation capacity, as illustrated later in Figure 50. Similar phenomena can be charted for Mexico (where the industrialized northeast and border regions have driven natural gas demand) and Canada (with gas demand increasing both in the Rocky Mountain region, including power for oil sands projects, and burgeoning urban areas along that border). In all cases, however, many of the prevailing forces that impact demand are the same.

Figure 46. Natural Gas Consumption by U.S. Census Region, 1997-2002



Source: U.S. EIA

Figure 47. U.S. Natural Gas Demand Sensitivity



Source: IHSEnergy

Demand Response - Overview

The many different users of natural gas have different sensitivities to price ("price elasticities" as noted earlier) and will stop using natural gas if the price becomes too high relative to other costs and to total disposable income or earnings, and relative to costs for competing fuels on an energy equivalent basis. Should high price levels continue for extended periods of time the drop in demand may become permanent. Figure 47 above left shows one estimate of the range of potential changes in demand for natural gas that can result from a variety of actions. The major factors and responses by different customer groups to natural gas prices are as follows.

Weather

Natural gas is used primarily within the residential and commercial sectors for space heating. Harsher and longer heating seasons (colder than usual winter months) lead to increased demand for natural gas. Conversely, warmer temperatures on average means less natural gas would be used. Figure 47 above indicates a potential four Bcf/d difference just for residential users between mild and more severe winter weather conditions.

Summer is the cooling season and electric power generated from natural gas is critical to serve air conditioning demand on the hottest days. Most peaking plants (which run during summer afternoons when air conditioning use increases, especially on hotter than normal days) are fueled by natural gas. As a result, demand for natural gas also increases during abnormally warm summers. Importantly, however, has been the surge in growth in permanent "sun belt" residential and commercial demand for cooling across the southern U.S. as population growth and housing and commercial development have boomed.

Because of these seasonal variations in demand for natural gas, storage facilities play a crucial role in stabilizing the marketplace. The U.S. natural gas industry has developed more storage capacity than any other country – more than 400 storage facilities (salt caverns and depleted gas fields) provide about 85 Bcf of deliverability per day.[69] Also in the U.S., there are roughly 100 LNG storage facilities that are used for "peak-shaving" purposes, i.e., to provide a greater amount of delivered gas when demand surges during hottest and coldest days.

Switching

Fuel switching has potential impact to the extent that local environmental regulations allow and to the extent that the facilities in question have the technical capability to switch fuels. Permanent or temporary shutdowns may also occur for facilities like ethylene, methanol and ammonia plants, for which natural gas is the primary feedstock.

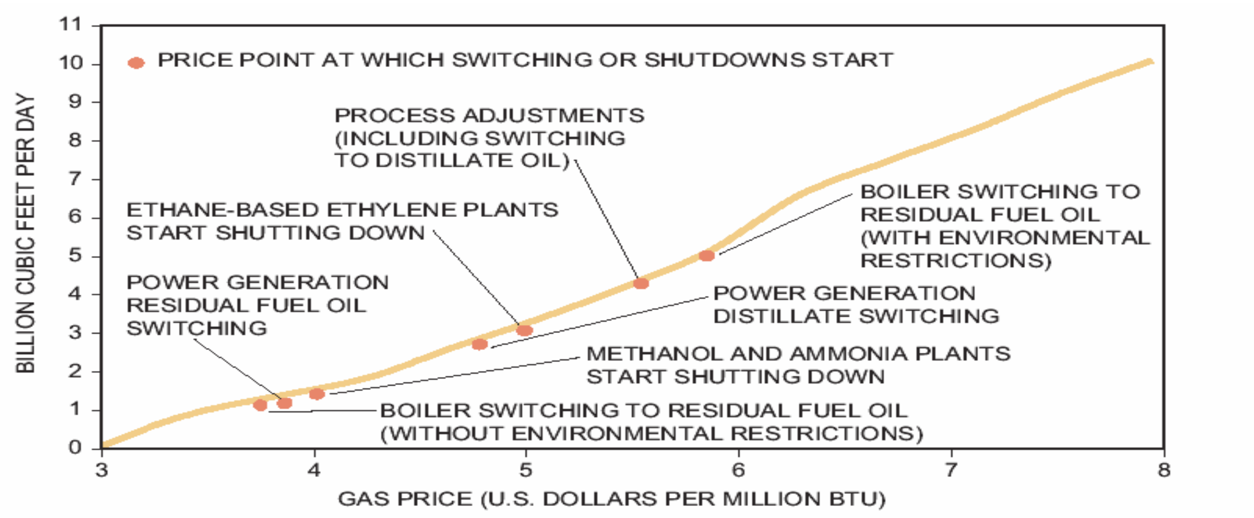
Industrial demand for energy is sensitive to variations in prices for different fuels, and which fuels are used is a function of competing prices on an energy equivalent (Btu) basis. Sustained high natural gas prices may cause a drop of more than three Bcfd in industrial demand, as shown in Figure 47. If natural gas prices are high enough for a long enough period (relative to the prices for alternative fuels), this drop in demand may translate into a permanent loss of one Tcf a year. Some industrial users and power plants have equipment which is capable of using fuels besides natural gas, such as residual fuel oil or distillate (both produced from crude oil). Switching will depend heavily on the price of these alternative fuels relative to natural gas on a Btu basis. Large energy users without dual fuel capable equipment already in place must consider the cost of installing this equipment as well as the cost of the competing energy fuels. Figure 48 below provides some estimates of the amount of switching that takes place at different natural gas price levels while keeping alternative fuel and plant output prices the same. At an average natural gas price of around $4 per million Btu (MMBtu), around two Bcf/d of switching can occur. Power generators can switch an additional 2-2.5 Bcf/d

---

[69] EIA: *U.S. LNG Market and Uses: June 2004 update*

capacity to distillate if the natural gas price hovers around $5 per MMbtu. A sustained natural gas price of around $6 per MMBTU may trigger additional switching of up to 8-9 Bcf/d. In annual volumes, 0.7 Tcf, 1.5-1.6 Tcf and up to five Tcf of demand reduction may be observed due to switching at $4, $5 and $6 price environments, respectively.

Figure 48. Industrial and Power Generation - Natural Gas Flexibility



Source: NPC

Environmental considerations may restrict the ability of some users to switch fuels depending on the alternative fuel they chose, the location of their facilities, and the terms and conditions of their air quality permits. If the price of alternative fuels or plant outputs increase along with the price of natural gas, switching will be economically limited. For these and other reasons, some power generators and industrial gas users have retired or mothballed boilers and other equipment capable of using dual fuels, such as oil and gas.[70] In addition, not using oil or coal in current or retiring processes yielded the emission credits that were needed for plant expansions or new process construction. Some plant sites, once capable of using dual fuels now lack the permits to burn fuels other than natural gas and/or lack both the infrastructure and the physical storage capacity for using alternative fuels.

[70] National Petroleum Council: *Balancing Natural Gas Policy - Fueling the Demands of a Growing Economy*. *Volume I- Summary of Findings and Recommendations*, Sept. 2003. See www.npc.org.

A consideration is the impact of recent changes in the New Source Review process associated with the Clean Air Act, which relaxed the U.S. Environmental Protection Agency's (U.S. EPA's) "routine maintenance" interpretation. With the new rule, utilities can avoid having to pay for expensive emission-cutting devices for up to 20 percent of their replacement costs for key equipment even if the upgrade increases emissions. This rule may encourage 30,000 megawatts (MW) of "new" coal-fired generation capacity to enter the market, potentially displacing two Tcf-equivalent of natural gas demand. Higher natural gas prices may induce some utilities to pursue coal capacity expansion more aggressively. Utilities may expand capacity sooner or the expansion may be larger. However, the legality of the new source review rule is being challenged and it may be turned over in U.S. courts. Apart from new source review, economic consequences of higher natural gas prices have encouraged discussion about how to adapt more flexible rules so that oil and coal can be used during peak periods of electricity demand if these fuels are cheaper.[71]

Shut-ins and Shut-downs

Shut-ins and shutdowns are the decisions of industrial users of natural gas to temporarily or permanently close plants, respectively. These actions occur when industrial users are facing a situation where the plant is operating at a loss, or the profits from selling natural gas supplies they had bought with long term contracts exceeds the profits the plant was expected to generate. For example, from Figure 48 above, methanol and ammonia plants start shutting down at around $4 per MMBtu and ethylene plants start shutting down at around $5 per MMBtu, accounting for a demand reduction of 1.5 Bcf/d and 3 Bcf/d, respectively. These figures imply an annual demand loss of 0.5 Tcf and 1.5 Tcf.

In open, competitive markets, demand will adjust to changes in price. The issue for the natural gas industry today is whether supply-side constraints are resulting in price effects to such an extent that economic activity is hindered. The chemical and steel industries are the largest users of natural gas in the industrial sector. The bulk chemical industry uses natural gas as a feedstock and as a fuel. On a Btu

[71] U.S. EIA workshop on natural gas, July 25, 2003.

basis 55 percent of both the energy and feedstock used each year by the chemical industry per average dollar of output comes from natural gas.

The industrial sector produces a wide range of basic materials, such as cement, steel and chemicals that are typically not used directly but used to produce goods for final consumption. Energy is an especially important input to the production processes of industries that produce these basic materials. Companies operating within the industrial sector compete among themselves and with foreign producers for sales to consumers. Many basic materials are commodities, making producers utilizing these basic materials indifferent to their source of production. Consequently, variations in input prices can have significant competitive impacts.

Natural gas prices differ significantly around the world, due to government regulations, pricing structures and the natural gas supply mix of imports and domestic production in any country. As a result of natural gas cost differences, basic material producers in other countries can have a cost advantage over domestic basic material producers.

In one opinion, "Sustained high natural gas prices are likely a drag on U.S. economic activity. A rough estimate is that a sustained doubling of natural gas prices would reduce U.S. gross domestic product (GDP) by 0.6 to 2.1 percent below what it would otherwise be."[72] In 2002, total GDP for the United States in nominal dollars was $10,442.6 billion.[73] Thus the impact of a doubling in natural gas prices on the national economy would range between $62.6 and $219.3 billion dollars in lost economic output.

Conservation and Efficiency

Although not explicit in Figure 47, conservation and efficiency measures may also lower natural gas use permanently across all demand sectors. Conservation

---

[72] Testimony before the House Resources Committee, U.S. Congress, by Stephen Brown, director of energy economics and microeconomic policy analysis for the Federal Reserve Bank of Dallas. See http://resourcescommittee.house.gov/108cong/energy/2003jun19/brown.htm.
[73] U.S. Bureau of Economics Analysis, http://www.bea.doc.gov/bea/dn/gdplev.xls.

represents a new dynamic - that of price induced adjustments among residential and small commercial customers. Based on anecdotal information from large utilities, these adjustments are expected to be permanent and come mainly in the form of investment in new furnaces and other equipment. Users of natural gas can lower their consumption by replacing and upgrading to equipment that either uses less natural gas or utilizes other fuels. This can be costly for end users and also trigger increased demand for other fuels, the prices of which may then rise.

Some residential, commercial, and industrial users of natural gas may decide not to forgo consumption but will repair, upgrade, or replace equipment and operations to use less natural gas. They will repair, upgrade, or replace equipment in order to use less natural gas. The expected savings from reduced consumption will motivate those who chose to follow this route.

Natural Gas Transmission System Issues – Factors and Trends

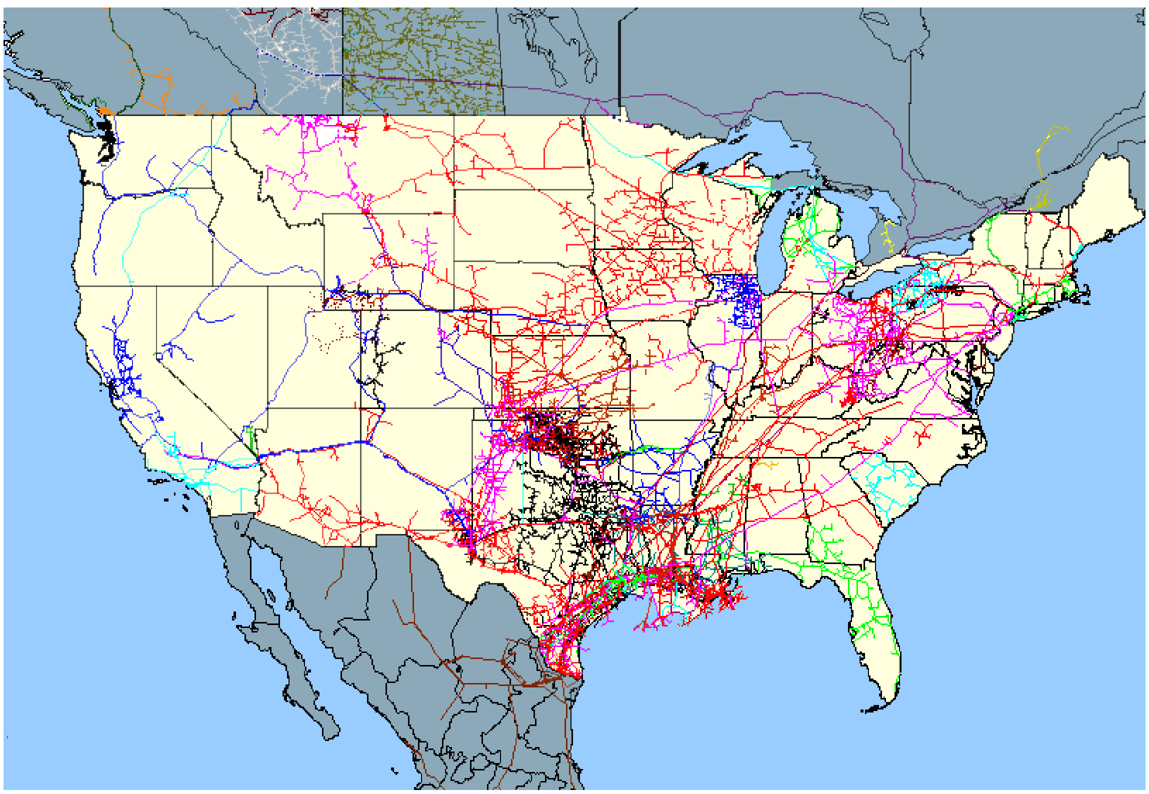
Apart from the questions of developing natural gas supplies and how demand adjusts to changes in availability and price are issues regarding the adequacy of the vital North American pipeline grid. In particular, a number of pipeline transportation issues must be addressed for LNG to play a more meaningful role in the future, as well as to improve access to domestic supplies.

Location of Demand for Natural Gas

As the natural gas industry evolved in the U.S., Canada and Mexico, new natural gas supplies were discovered increasingly further away from the major markets. As a result, the major, large diameter, long distance pipelines that evolved were designed to carry natural gas production from these distant locations – from the southwestern U.S. and onshore and offshore fields in the Gulf of Mexico region, from the WCSB and from Mexico's huge Reforma-Campeche producing basin near the Yucatán – to burgeoning urban centers and coastal populations elsewhere. A particular issue to be addressed for LNG is enhancing pipeline capacity to transport supplies from coastal receiving locations to demand centers. In many cases, this means adding new pipeline capacity or altering existing capacity to accommodate pipeline flows that will be the reverse of traditional patterns. In addition, while the demand for natural gas in the U.S. varies from state to state (as explained with respect to Figure 45 and Figure 46 above), it has been among the coastal states, where population growth has been strongest, that gas demand has also been most pronounced.

Figure 49 illustrates the extent to which the pipeline grids have evolved to carry gas generally east or west, in the case of Canada and the Lower 48 states, to major markets on the east and west coasts. Intense pipeline development along the U.S. Gulf Coast serves to aggregate gas across the numerous producing fields as well as to support the intensive natural gas-based industrial activity in that region.

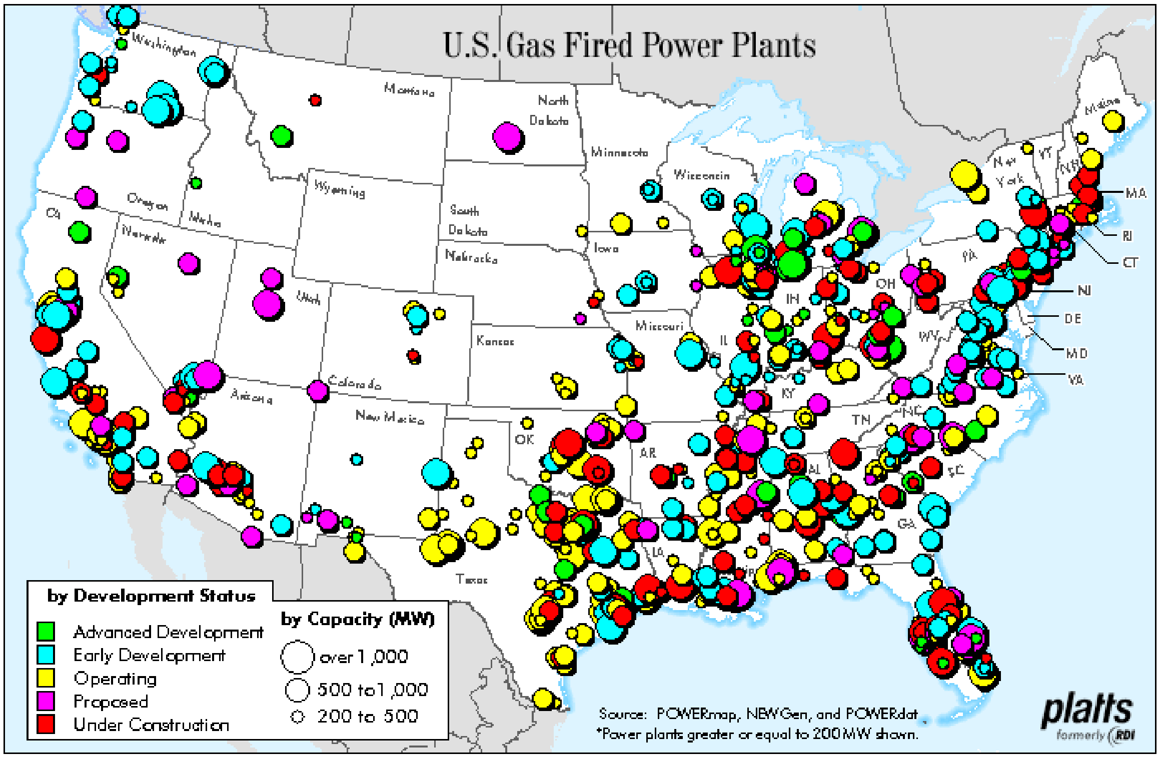
Figure 49. U.S. / North American Pipeline Grids



Source: PennWell

Pipeline routes, which connect natural gas production to markets and connect population centers along the way, have also served as locations for new gas-fired power generation, as shown by comparing Figure 49 above and Figure 50 below.

Figure 50. US Gas Fired Power Plants



Source: Platts

Natural Gas Pipeline Takeaway Capacity

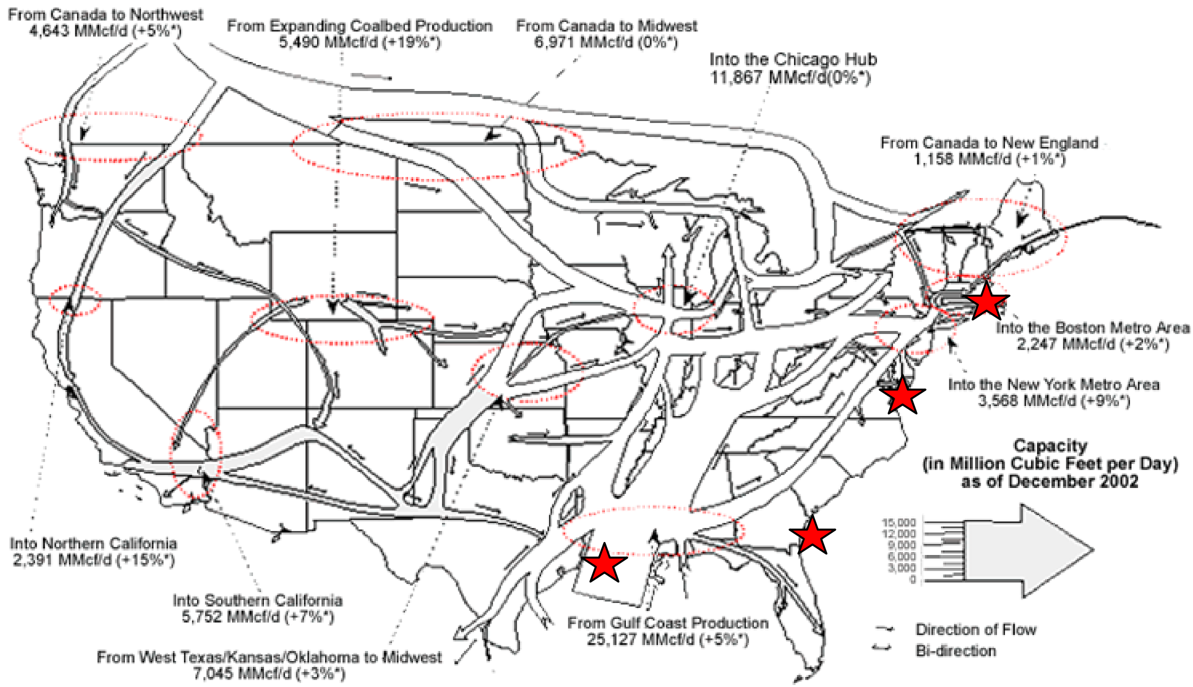
At the close of 2002, the U.S. had about 212,000 miles of interstate natural gas pipeline connecting major natural gas market centers. The picture for major U.S. pipelines is more dynamic than many realize. During 2001, more than 3,500 miles of pipeline were added to the U.S. system, in spite of national events and a drop in natural gas usage, and a number of projects were planned for 2003.[74] Proximity to existing pipelines with sufficient capacity to transport natural gas from LNG terminal locations, or ability to certify and construct a new pipeline is a major consideration in siting new LNG facilities in the U.S.

A number of new LNG terminals are proposed to be located along the U.S. Gulf of Mexico where the existing pipelines and interconnections are quite dense (proximity to Henry Hub also helps for pricing). Pipelines originating from the Gulf Coast can

[74] U.S. EIA, Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/pipenet03.html.

become congested during peak periods of the year, and distances from the Gulf Coast to natural gas markets in the U.S. Midwest and Northeast are quite long. Yet, as shown in Figure 51, the U.S. Gulf Coast Provides the largest "fairway" for moving gas into and throughout the Lower 48. Figure 51 also clearly shows the pipeline adjustments that would need to take place to accommodate new LNG import terminal locations (by comparing the four existing locations, designated by red stars, and planned and proposed projects as updated by the FERC).[75]

Figure 51. Major Pipeline Capacity Levels in 2002 and Change from 2000



*Percent change since 2000.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Pipeline State Border Capacity Database.

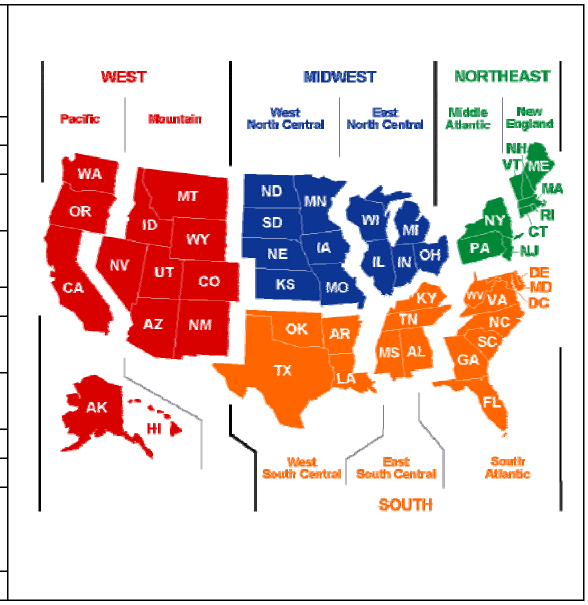
Table 2 indicates how pipeline capacity utilization varies around the U.S and where some of the "bottlenecks" in the U.S. pipeline system that could impact access to LNG supplies are located. Data on pipeline utilization represent a snapshot in time of how pipeline capacity is used; utilization varies greatly during the course of a year depending upon seasonal usage and economic activity. Much of the renovation that would be done to the U.S. pipeline system will happen over the longer term as part of overall development for new LNG import facilities, and will

[75] See note 38.

entail capacity expansions to both U.S. interstate pipelines and "intrastate" pipelines that operate within state boundaries.

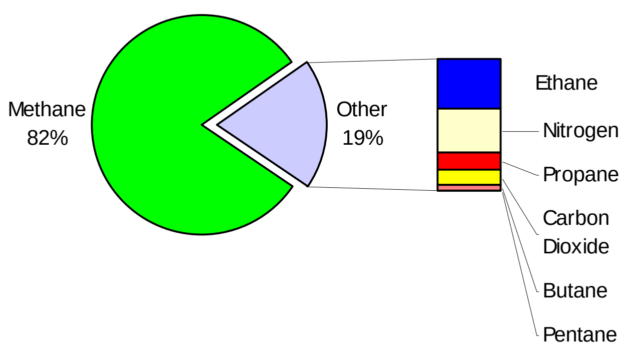
Table 2. Natural Gas Pipeline Capacity Utilization, 2002[76]

U.S. Census Division	Utilization Entering Region (Imports)	Utilization Exiting Region (Exports)
New England	0.69	0.91
Middle Atlantic	0.59	0.41
East North Central	0.56	0.54
West North Central	0.54	0.53
South Atlantic	0.60	0.48
East South Central	0.62	0.63
West South Central	0.25	0.51
Mountain	0.14	0.46
Pacific	0.61	0.13
Average Capacity Utilization	**0.55**	**0.52**
United States	0.72	0.53



Natural Gas Quality and Interchangeability

Figure 52. Typical Composition of Natural Gas[77]



Natural gas is composed primarily of methane, but may also contain propane, butane, ethane and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds, and water may also be found in natural gas. Figure 52 provides a typical natural gas composition. "Gas quality" varies across production fields and depends upon whether the natural gas production is in association with crude oil (associated or non-associated gas) or as gas condensate (gas liquid that is

[76] Capacity utilization is defined as the annual throughput volume divided by the pipeline design capacity. Average capacity utilization is the weighted average utilization using the regional pipeline capacity levels as weights. *Source: Energy Information Administration, AEO2004 National Energy Modeling System run aeo2004.d101703e.*
[77] Danesh, Ali: *PVT and Phase Behavior of Petroleum Reservoir Fluids,* Elsevier, 1998.

separated from either associated or non-associated natural gas production in the field). Gas quality is a consideration for both domestic (North American) production and for LNG cargos, many of which derive from producing regions in which the non-methane, hydrocarbon components of natural gas are relatively high (water and other impurities are removed before natural gas is liquefied).

Generally, 41 percent of natural gas reserves in the U.S. must be treated for excessive impurities.[78] Producers and third party gas processors continue to remove impurities such as hydrogen sulfide, water, CO2 and a dozen other compounds to meet the gas quality specifications of interstate pipeline tariffs.

- Water which enters as vapor or liquid: Water vapor can condense to liquid water and can result in freezing and corrosion in pipelines and equipment. Water collects in low spots. Virtually no internal corrosion occurs without liquid water.
- Carbon dioxide, hydrogen sulfide and oxygen: These gases react with liquid water and with each other causing corrosion. The byproducts of internal corrosion can lead to wear and damage of the pipeline, compressors and measurement equipment.

In the pipeline, when the gas temperature falls below the hydrocarbon dewpoint it begins to "rain" hydrocarbons. The dewpoint is the temperature below which some components in the natural gas stream begin to condense and drop out as liquids. These liquids must be removed by frequently "pigging" the pipeline to keep it clean. Free liquid hydrocarbons may interrupt the reliability of instrumentation, controllers and safety devices. They may contaminate equipment fuel lines, resulting in major damage to turbines and reciprocating equipment, and may cause increased pressure drop and loss of capacity. Free liquid hydrocarbons may also freeze regulators and controllers and contaminate customer facilities. Thus natural gas that contains a high dew point is a danger to the safe operation of pipelines and to consuming customers.

---

[78] Jeryl L. Mohn, Panhandle Energy - *Gas Quality and Interchangeability 101*, Presentation at FERC Conference on Natural Gas Interchangeability and Quality Standards, February 18, 2004.

Heat energy is generated by burning natural gas. Higher heating value (HHV) is the energy generated by combustion (including the heat that turns the water created into steam). HHV is the standard measure used for commercial natural gas transactions and is generally expressed in dekatherms (dth).[79] The composition of natural gas with respect to hydrocarbon components determines the heating value of the gas.

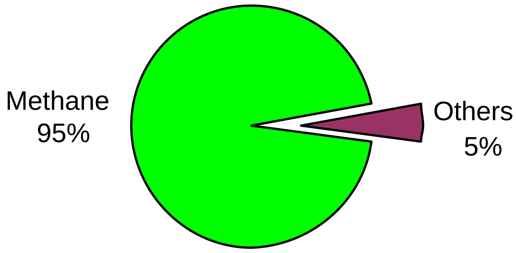
Because of the potential for operational problems and safety related to the presence of liquid hydrocarbons, BTU limits have traditionally been used to monitor liquid dropout and control gas quality for pipeline operations. Other limits exist to help manage and limit corrosion. Two factors have impacted gas quality in recent years. One is the arrival of rich (larger amounts of liquid hydrocarbons) deepwater U.S. Gulf of Mexico production. The second is the current situation in which natural gas liquids (NGLs) derived from processing natural gas are not as valuable as the residual gas stream, a function of the current high valuation of methane for domestic applications. These conditions have led to discussion of alternative and more accurate measurements to control gas quality, such as dew point limitation, through the natural gas tariffs established by regulatory agencies. Gas quality tolerances for newer end-use equipment, such as low emission combustion turbine electric generators and pipeline compressors, are tighter than those for older end-use appliances and equipment. As a consequence, operators of newer equipment are increasingly sensitive to gas quality. For certain end-users, the variability of gas quality, primarily heating value, could also affect the ability to achieve environmental performance criteria and could void manufacturer warranties.

For LNG, as noted above, the natural gas liquefaction process requires the removal of some of the non-methane components such as water and carbon dioxide from the produced natural gas to prevent them from forming solids when the gas is cooled to about LNG temperature (-256^{O}F). As a result, LNG is typically made up mostly of methane as shown in Figure 53.

---

[79] See Appendix for definitions.

Figure 53. Typical LNG Composition



LNG comes from many different sources and can have different compositions. Examples of LNG composition are shown in Table 3. LNG water content is zero.

Table 3. Examples of LNG Composition

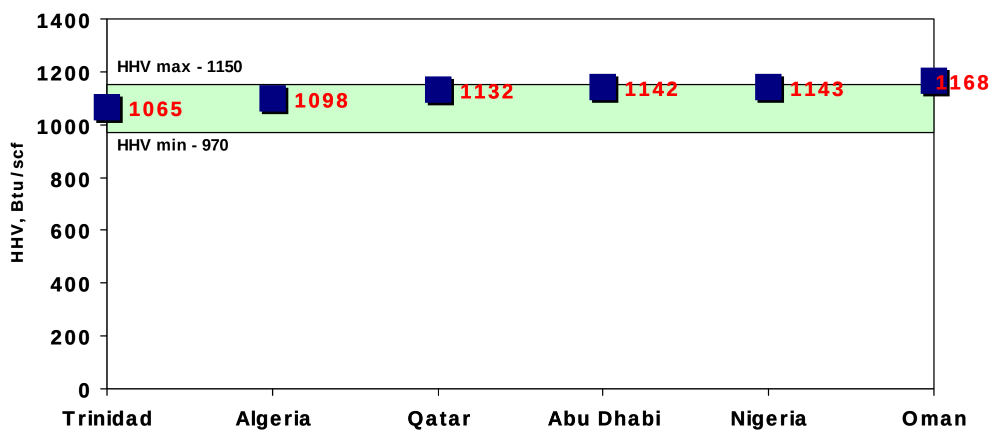
LNG COMPOSITION (Mole Percent)

Source	Methane	Ethane	Propane	Butane	Nitrogen
Alaska	99.72	0.06	0.0005	0.0005	0.20
Algeria	86.98	9.35	2.33	0.63	0.71
Baltimore Gas & Electric	93.32	4.65	0.84	0.18	1.01
New York City	98.00	1.40	0.40	0.10	0.10
San Diego Gas & Electric	92.00	6.00	1.00	-	1.00

Source: *Liquid Methane Fuel Characterization and Safety Assessment Report* . Cryogenic Fuels. Inc. Report No. CFI-1600, Dec. 1991

Figure 54 below shows the HHV of LNG from different sources compared to a typical U.S. pipeline tariff range. LNG heating value depends on the percent composition of heavy hydrocarbons; ethane, propane and butane.

Figure 54. LNG HHV Relative to Typical Pipeline Tariff Range



Source: WGL

LNG properties can be managed by processing to remove non-methane hydrocarbons at LNG production or LNG vaporization by injecting inert gases or blending with domestic natural gas before pipeline shipment.

The prospects for significantly increased future LNG imports have introduced the prospect of greater variability in the heating value (and perhaps other qualities) of natural gas introduced into the North America pipeline system. This is an issue of gas interchangeability (which defines the ability for two distinct gases to be used in essentially the same manner with regard to end use applications).

The University Of Houston Institute For Energy, Law & Enterprise (IELE) has prepared a technical briefing paper, *"Interstate Natural Gas -- Quality Specifications & Interchangeability"* that addresses issues concerning gas quality and interchangeability.[80]

[80] See www.beg.utexas.edu/energyecon/lng. The CEE has filed comments in a FERC docket on Natural Gas Interchangeability, Docket No. PL04-3-000, available from the FERC web site www.ferc.gov.

Appendix 2: LNG Frequently Asked Questions[81]

What is LNG?

Liquefied Natural Gas (LNG) is natural gas cooled to a liquid state. When natural gas is cooled to a temperature of approximately -256°F at atmospheric pressure, it condenses to a liquid. To liquefy natural gas, impurities that would freeze, such as water, carbon dioxide, sulfur, and some of the heavier hydrocarbons are removed. The volume of this liquid takes up about 1/600th of the volume of natural gas at a stove burner tip. LNG weighs about 45 percent as much as water and is odorless, colorless, non-corrosive, and non-toxic.

What is the history of LNG?

The liquefaction of natural gas dates back to the early 1900s. The first practical compressor refrigeration machine was built in Munich in 1873. The first LNG facility was built in West Virginia in 1912 and began operation in 1917. The first commercial liquefaction facility was built in Cleveland, Ohio, in 1941. In January 1959, the world's first LNG tanker, *The Methane Pioneer*, a converted World War II Liberty freighter containing five, 7000 Bbl aluminum prismatic tanks with balsa wood supports and insulation of plywood and urethane, carried an LNG cargo from Lake Charles, Louisiana to Canvey Island, United Kingdom. This event demonstrated that large quantities of liquefied natural gas could be transported safely across the ocean. LNG has also been used as a vehicle fuel since the mid 1960s.

---

[81] Sources of the materials used in this section include:
1. Department of Energy, Alternative Fuels Data Center, http://www.afdc.doe.gov/altfuel/natural_gas.html.
2. Applied LNG Technologies, http://www.altlngusa.com/ngf_lng.htm.
3. Australia LNG, http://www.australialng.com.au/.
4. BG Group, http://www.bg-group.com/group/LNG_2001.htm.
5. BP LNG, http://www.bplng.com/.
6. CH-IV, http://www.ch-iv.com/lng/lngfact.htm.
7. Chive Fuels, http://www.lng-cng.com/chivefuels/liquefiednaturalgas.htm.
8. Crystal Energy, LLC, http://www.crystalenergyllc.com/index.html.
9. Dominion Cove Point, LNG, http://www.dom.com/about/gas-transmission/covepoint/faq.jsp.
10. El Paso, http://www.elpaso.com/business/LNG_FAQ.shtm.
11. North Star Industries, http://northstarind.com/lngfaqs.html.
12. Ras Laffan Industrial City, http://www.qp.com.qa/raslaffan/rlc.nsf/web/introlngfacts#.
13. Federal Energy Regulatory Commission (FERC), http://www.ferc.gov/for-citizens/lng.asp.

What is the composition of LNG?

Natural gas is composed primarily of methane (typically, at least 90 percent), but may also contain ethane, propane and heavier hydrocarbons and small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds, and water. The liquefaction process that produces LNG removes any oxygen, carbon dioxide, sulfur compounds, and water.

Where does LNG come from?

LNG supplies come primarily from locations where large gas discoveries have been made and countries that produce a lot of gas associated with oil fields, such as Algeria, Trinidad, Nigeria, Indonesia, Qatar, Oman, Malaysia, Libya, Abu Dhabi, Brunei and Australia. Some LNG is produced in Alaska as well.

Can difference between foreign LNG and U.S. pipeline gas cause any problem?

Foreign LNG sometimes has a higher heating value than typical U.S. pipeline natural gas. However, LNG terminal operators measure heating values and respond with a number of techniques, such as blending, dilution, or adding an inert component, which insures compatibility with U.S. pipeline gas. The fact that foreign LNG has been imported for over 25 years into Boston and Lake Charles and then mixed into the U.S. pipeline network without incident proves that this is not a significant safety issue.

Why liquefy natural gas?

Converting natural gas to a liquid reduces its volume by about 600 to 1. Liquefying natural gas makes it feasible to transport natural gas by tanker and to store it in preparation for re-gasification and delivery to markets.

How is natural gas liquefied?

A large refrigeration system liquefies natural gas by cooling it to -256 degrees Fahrenheit.

How many LNG facilities are there in the U.S.?

There are 113 active LNG facilities in the U.S. Natural gas is liquefied and stored at about 58 facilities in 25 states and 96 LNG storage facilities are connected to the natural gas pipeline grid. Massachusetts alone accounts for 14 major satellite facilities, or roughly 40 percent of all satellite facilities in the United States. There are five satellite LNG facilities in New Jersey, the second highest in the U.S. There are currently over 200 peak shaving and LNG storage facilities worldwide, some operating since the mid-1960s.

How is LNG used?

LNG is used worldwide for established, as well as emerging applications:

World Trade. Natural gas is liquefied and transported by ship from remote reserves to markets in Asia, Europe and North America, where it is often used to *fuel electric power facilities*. Growing needs for electricity in Asia have increased demand for LNG nearly 8 percent per year since 1980, making it one of the fastest growing energy sectors.

Seasonal Gas Storage. Roughly 100 LNG facilities, called peak shaving facilities, have been constructed worldwide to liquefy and store natural gas during warmer months for vaporization and injection into local pipelines during cold weather.

Alternative Motor Fuel to Diesel. With only one carbon and four hydrogen atoms per molecule, methane is the cleanest burning fossil fuel. In liquid form, much more fuel can be stored aboard vehicles than as compressed natural gas (CNG) so it is well suited for high-fuel-consumption vehicles.

What are the advantages of LNG?

LNG takes up 600 times less space than regular natural gas at ambient temperature and pressure, which makes it easier to transport and store than natural gas. LNG can be stored above or below ground in specially designed double walled storage tanks. LNG can be transported over long distances via double-hulled LNG ships, which are specially designed tankers that keep the LNG chilled during transport. LNG is also used to replace diesel in heavy-duty trucks and buses and new gas-fueled locomotives as a lower emissions alternative.

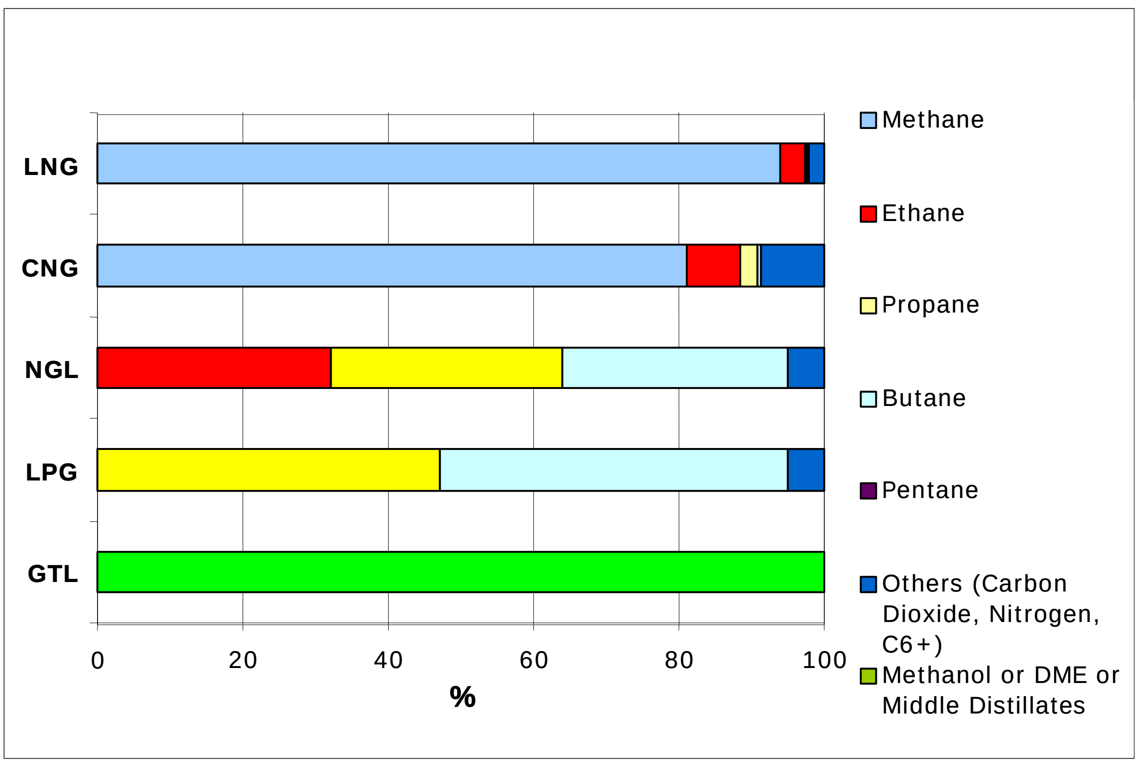
What are the disadvantages of LNG?

LNG operations are capital intensive. Upfront costs are large for construction of liquefaction facilities, purchasing specially designed LNG ships, and building re-gasification facilities. Methane, a primary component of LNG, is considered a greenhouse gas because it increases carbon levels in the atmosphere when released.

What is the difference between LNG, CNG, NGL, LPG, and GTL?

It is important to understand the difference between Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG), Natural Gas Liquids (NGL), Liquefied Petroleum Gas (LPG), and Gas to Liquids (GTL). Figure 55 shows the difference in typical composition of these products.

Figure 55. Typical Composition of LNG, NGLs, CNG, GTL, and LPG



LNG is made up of mostly methane. The liquefaction process requires the removal of the non-methane components like carbon dioxide, water, butane, pentane and heavier components from the produced natural gas. CNG is natural gas that is pressurized and stored in welding bottle-like tanks at pressures up to 3,600 psig.

Typically, CNG is the same composition as pipeline quality natural gas. NGLs are made up mostly of molecules that are heavier than methane like ethane, propane, and butane. LPG is a mixture of propane and butane in a liquid state at room temperatures. GTL refers to the conversion of natural gas to products like methanol, diethyl ether (DME), middle distillates (diesel and jet fuel), specialty chemicals and waxes.

Who regulates LNG industry in the U.S.?

In the U.S., the LNG industry is governed by federal, state and local agencies.

Federal agencies include:
Department of Transportation (DOT)
Federal Energy Regulatory Commission (FERC)
Coast Guard (USCG)
Environmental Protection Agency (EPA)
Fish and Wildlife Service
Army Corps of Engineers
Minerals Management Service
Department of Labor Occupational Safety & Health Administration (OSHA).

How does LNG benefit the United States?

LNG supplements America's natural gas supply at a competitive cost. Natural gas is the fuel of choice for the vast majority of new power facilities being built in the country today. Because of this demand, the domestic natural gas market is expected to grow from 22 trillion cubic feet to 30 trillion cubic feet within the next 10 years. To help meet that growing demand, LNG will play an increasingly larger role in the country's energy supply mix.

How is LNG transported for export?

LNG is transported in specially designed ships to re-gasification facilities. These ships are double-hulled and have capacities from 25,000 to 138,000 m^3 or more. The ships are fitted with a special cargo containment system inside the inner hull to maintain the LNG at atmospheric pressure and -256°F. There are about 145 ships currently in the global LNG fleet and more than 56 additional ones are on order.

What facilities make up an LNG import terminal?

An LNG import terminal consists of berths for mooring ships to discharge LNG onshore via pipelines, LNG storage tanks, and vaporizers that turn LNG from a liquid back into natural gas, as well as utilities for operating the facility.

How is LNG stored?

LNG is stored in tanks designed to contain the product safely and securely. Storage tank designs vary. Large tanks are low aspect ratio (height to width) and cylindrical in design with a domed roof. LNG is stored at atmospheric pressure. LNG must be maintained cold to remain a liquid, independent of pressure.

How is LNG kept cold?

Insulation, as efficient as it is, will not keep the temperature of LNG cold by itself. LNG is stored as a *boiling cryogen* -- a very cold liquid at its boiling point given the pressure at which it is being stored. Stored LNG is analogous to boiling water, only 472°F colder. The temperature of boiling water (212°F) does not change, even with increased heat, as it is cooled by evaporation (steam generation). In much the same way, LNG will stay at near constant temperature if kept at constant pressure. This phenomenon is called *auto refrigeration*. As long as the steam (LNG boil off vapor) is allowed to leave the tea kettle (tank), the temperature will remain constant. This boil off is captured by the LNG facilities and ships and used as fuel or sent to the pipeline grid.

What are the regulatory requirements for LNG ships?

LNG ships must comply with relevant local and international regulatory requirements including those of the International Maritime Organization (IMO), International Gas Code (IGC) and the USCG. All LNG ships must also comply with host Port Authority requirements.

Is LNG safe?

LNG has been safely handled for many years. The industry has maintained an excellent safety record, especially over the past 40 years. The safe and environmentally sound operation of these facilities, both ships and terminals, and the protection of these facilities – like other critical parts of the energy infrastructure -- from terrorist activities or other incidents are a concern and responsibility shared by operators as well as federal, state and local authorities across the U.S. Onshore LNG facilities are industrial sites and, as such, are subject to all rules, regulations and environmental standards imposed by the various jurisdictions. These same or similar concerns apply to natural gas storage, pipeline transportation, distribution and consumption of natural gas.

Have there been any serious LNG accidents?

LNG is a form of energy and must be understood as such. Today LNG is transported and stored as safely as any other liquid fuel. In 1944, before the storage of cryogenic liquids was fully understood, however, there was a serious incident involving LNG in Cleveland, Ohio. This incident virtually stopped all development of the U.S. LNG industry for 20 years.

In addition to Cleveland, there are other U.S. incidents sometimes attributed to LNG. Some parties have cited a construction accident on Staten Island in 1973 as an "LNG accident" because the construction crew was working inside an empty LNG tank. In another case, the failure of an electrical seal on an LNG pump in 1979 permitted gas (not LNG) to enter an enclosed building. A spark of indeterminate origin caused the building to explode. As a result of this incident, the electrical code has been revised for the design of electrical seals used with all flammable fluids under pressure.

On January 19, 2004 there was an explosion at the Sonatrach’s Skikda LNG export plant in Algeria that killed 27 people. According to Sonatrach, at 6:40 pm there was an explosion at train 40. The blast damaged trains 30 and 20 that were in operation. The LNG storage tanks were not damaged by the explosion. The plants were shut down and the fire, after burning eight hours, was extinguished by the industrial and regional fire brigades following planned emergency procedures. Investigations are ongoing.[82]

How does an LNG fire compare with other fuel fires?

Fighting an LNG spill fire is very similar to fighting any hydrocarbon fire. Techniques have been refined over the years to cope with LNG as with any other hydrocarbon fire. The Texas A&M fire school and Northeast Gas Association have been training fire fighters and other industry professionals on LNG spill fires for over 25 years. Development of special dry chemical and high expansion foam systems to control LNG fires began with a series of industry sponsored tests and resulted in engineering data that permit the LNG facility designer to configure very reliable LNG fire control systems.[83],[84]

Will LNG burn?

LNG vapor, mainly methane (natural gas), burns only within the narrow range of a 5 to 15 percent gas-to-air mixture. If the fuel concentration is lower than 5 percent, it cannot burn because of insufficient fuel. If the fuel concentration is higher than 15 percent, it cannot burn because there is insufficient oxygen. For LNG to burn, it must be released, vaporize, mix with air in the flammable ratio, and be exposed to an ignition source. From an environmental standpoint there is very little smoke associated with an LNG fire.

Will LNG explode?

Explosion is a hazard unlikely to occur with LNG activity. LNG in liquid form itself will not explode within storage tanks, since it is stored approximately -256°F (-160°C) and at atmospheric pressure. Without pressure or confinement or heavily obstructed clouds of the vapors, there can be no explosion. An explosion from a

---

[82] Bachir ACHOUR & Ali HACHED; Sonatrach: The *Incident at the Skikda Plant: Description and Preliminary Conclusions*," LNG14, Session 1, DOHA-Qatar, March 2004,.
83 H. H. West, L.E. Brown and J.R. Welker, Vapor Dispersion, Fire Control, and Fire Extinguishment for LNG Spills, Proceedings of the Spring Technical Meeting of the Combustion Institute, San Antonio (1975).
84 Fire Protection Handbook, Volume II, Gulf Publishing, Houston (1983).

release of LNG vapors is possible only if all the following conditions occur at the same time: vapors are in the flammability range, vapors are in a confined space and a source of ignition is present.

Is an LNG spill detectable?

Within an LNG facility or onboard a ship, there are various types of detectors used to alert personnel to a leak or spill. These could include detectors for the presence of gas, flame, smoke, high temperatures or low temperatures. While LNG vapors have no odor or color, if an LNG release occurs, LNG's low temperature causes water vapor to condense in the air and form a highly visible white cloud.

Would an LNG spill mean similar pollution to an oil spill?

If LNG were to leak, it would quickly evaporate leaving no residue when it came into contact with soil or water; so there is no need for environmental clean up of LNG spills on water or land.

How are LNG terminals designed to be safe?

Safety features include gas detectors; ultraviolet or infrared (UV/IR) fire detectors, closed circuit TV, offsite monitoring, personnel training requirements, and restricted access to terminal property. In addition, the stringent design parameters for LNG import terminals require that proper measures are in place in the unlikely event of a spill or equipment failure.

What are the public safety issues related to LNG?

Flammable Vapor Clouds

If LNG is released, the resulting LNG vapors (methane) will warm, become lighter than air, and disperse with the prevailing wind. Cold LNG vapor will appear as a white cloud.

If a source of ignition is present where LNG vapors (methane) exist at a 5 to-15 percent concentration in the air, the vapor cloud will burn along a flame front toward the source of the fuel.

It should also be noted that LNG vapors do not catch fire as easily as those of other common fuels such as gasoline or propane, and LNG vapors dissipate more easily, meaning that potential hazards can persist longer for other fuels than for LNG.

Fires

If LNG is released in the presence of an ignition source, a fire will result from the continuous evaporation of the LNG contained within the impoundment.

Since this fire would burn with intense heat, firefighting and other safety equipment is installed at terminals and onboard ships to help manage an incident.
"Liquefied Natural Gas Facilities: Federal Safety Standards" are found in Title 49 CFR Part 193.

How are LNG ships designed to be safe?

LNG ships are especially designed with a double hull to provide optimum protection for the cargo in the event of collision or grounding. The ship has safety equipment to facilitate ship handling and cargo system handling. The ship-handling safety features include sophisticated radar and positioning systems that enable the crew to monitor the ship's position, traffic and identified hazards around the ship. A global maritime distress system automatically transmits signals if there is an onboard emergency requiring external assistance. The cargo-system safety features include an extensive instrumentation package that safely shuts down the system if it starts to operate outside of predetermined parameters. Ships also have gas- and fire-detection systems, nitrogen purging, double hulls and double containment tanks or leak pans. Should fire occur on the ship, two 100 percent safety relief valves on each tank are designed to release the ensuing boil off to the atmosphere without over pressurizing the tank.

LNG ships use approach velocity meters when berthing to ensure that the prescribed impact velocity for the berth fenders are not exceeded. When moored, automatic mooring line monitoring provides individual line loads to help maintain the security of the mooring arrangement while alongside. When connected to the onshore system, the instrument systems and the shore-ship LNG transfer system acts as one system, allowing emergency shutdowns of the entire system from ship and from shore.

Aside from design features, are there additional safety measures for LNG ships?

To ensure safety for transportation of LNG, the USCG requires safety zones around LNG ships. The safety zones prohibit entry by other ships thereby helping to eliminate the possibility of a collision of an LNG ship with another ship. In fact, the concept of a safety zone is not confined to shipping. Like the safety zones applied in operating aircraft or automobiles and trucks, LNG safety zones allow a safe stopping distance in the event that another ship loses control. A USCG escort boat manages the safety zone around a ship. The USCG uses safety zones to centrally manage and coordinate shipping traffic in coordination with port authorities. Through the use of strict operational procedures, putting a priority on safety and well-trained, well-managed crews, shipping risks are well managed.

Is LNG environmentally friendly?

When LNG is vaporized and used as fuel, it reduces particle emissions to near zero and carbon dioxide (CO_2) emissions by 70 percent in comparison with heavier hydrocarbon fuels. When burned for power generation, the results are even more dramatic. Sulfur dioxide (SO_2) emissions are virtually eliminated and CO_2 emissions are reduced significantly. If spilled on water or land, LNG will not mix with the water or soil, but evaporates and dissipates into the air leaving no residue. It does not dissociate or react as does other hydrocarbon gases and is not considered an emission source. Additionally there are significant benefits when natural gas is used as fuel over other fossil fuels. However, methane, a primary component of LNG, is considered to be a greenhouse gas and may add to the global climate change problem if released into the atmosphere.

What happens if there is an LNG release at the storage facility?

An LNG release is very unlikely due to the strict design requirements for facilities. The design of LNG tanks and piping prevents releases or spills. But if there is a rupture of a segment of piping in the facility, a spill of LNG could occur. The facility is designed so that such a spill would be contained. Liquid would accumulate in one of several catch basins, where it would evaporate. Emergency shutdown systems would be involved to minimize any release. The tank impoundment in the facility can contain at least 100 percent of the LNG tank volume, which assures that the release from any accident will be fully contained. The rate of evaporation and the amount of vapors generated are dependent on the amount of liquid spilled and the surface area of the catch basin.

How are the LNG facilities designed to be safe?

All facilities that handle LNG have built-in systems to contain LNG and prevent fires. This is true whether in the LNG facility, transferring LNG to and from LNG ships, shipping LNG or vaporizing (re-gasifying) LNG. There are differences in design among these types of facilities, but the environmental, health and safety issues are the same.

Appendix 3: Why Natural Gas Markets are Liquid

Natural gas is a commodity and natural gas delivered from any pipeline system within the U.S. is essentially the same. The buying and selling of natural gas occurs within a "liquid" marketplace, meaning one in which there are a large number of credit-worthy participants. As such, natural gas prices move freely as buyers and sellers engage in transactions.

It is widely accepted that the price of natural gas at Henry Hub in southern Louisiana influences the pricing of natural gas elsewhere in the country. Henry Hub is the largest centralized point for natural gas spot and futures trading in the U.S. and, as mentioned in the main body of this report, is used by the NYMEX as the point of delivery for its natural gas futures contract. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas. NYMEX also provides a price discovery function through their open outcry system. The price at which natural gas can be bought or sold is known constantly and price adjusts quickly to supply-demand balances. Prices react quickly to changes in the future and current supply and demand for natural gas. Previous to the start of NYMEX natural gas futures trading, the only way to determine the cash value of natural gas was through newsletters and publications, which covered only the balance of the current month and the upcoming month.

Were the sharp increases in natural gas prices since January 2000 caused by market manipulation? This is an often-asked question. The combination of high natural gas and electric power prices triggered disruptions in western U.S. energy markets during 2000, ultimately leading to the collapse of many U.S. energy trading operations. Investigations of the 2000 natural gas price spike were carried out by the U.S. Commodity Futures Trading Commission (CFTC). The CFTC is charged with oversight of commodities trading and risk management. In some instances, the CFTC did find evidence to support market manipulation claims, and penalties were assessed.[85] Importantly, however, the majority of opinions are that the events of 2000 stemmed from growth in demand for natural gas that outpaced supplies.[86] The second, February 2003 price event was also investigated, and market manipulation was not found to be an issue.[87] At time of writing, the December 2003 price event is still under investigation.[88] An early indication was that evidence of market manipulation was lacking.[89] Overall, while isolated cases of improper natural gas trading have been identified and acted upon by CFTC, the overwhelming body of evidence is that natural gas market fundamentals shifted in favor of tighter supply-demand prices with increased price volatility as a result.[90]

Related to claims of market manipulation were separate charges that natural gas prices indexes, as compiled by commercial services and widely used by both suppliers and customers (including utilities), are unreliable. The U.S. FERC has conducted extensive investigations and research through its Office of Market Oversight and Investigations, and has reported broad improvements in the quality and reliability of natural gas price information.[91] Both issues, improper energy trading practices and quality of gas price reporting, adversely impact natural gas market liquidity, which in turn again impacts the process of natural gas "price discovery." The CFTC and joint CFTC-FERC actions as well as industry efforts on trading and oversight are critical to restoration of confidence, credit ratings, and liquidity.

---

[85] For example, see http://www.cftc.gov/opa/enf03/opa4869-03.htm, http://www.cftc.gov/opa/enf03/opa4824-03.htm and http://www.cftc.gov/opa/enf04/opa4883-04.htm.

[86] For an example of opinions regarding the role of natural gas supply-demand imbalances in California, see California Energy Commission, *California Natural Gas Analysis and Issues*, November 2000, http://www.energy.ca.gov/reports/2000-11-22_200-00-006.PDF.

[87] See http://www.cftc.gov/opa/opafercchairmen.htm for a joint statement by the U.S. CFTC and U.S. Federal Energy Regulatory Commission (U.S. FERC) on this investigation.

[88] See CFTC's Weekly Report, http://www.cftc.gov/opa/adv04/opawa05-04.htm, for an announcement on the investigation of the December 2003 price event.

[89] See "CFTC says investigating US natgas price spike," *Reuters Power News*, January 28, 2004.

[90] CFTC Chairman James Newsome commented on the CFTC's energy market investigations, http://www.cftc.gov/opa/speeches04/opanewsm-51.htm. Roughly $200 million in fines have been levied by CFTC for both natural gas and electric power trading infractions, not an insignificant amount, but a minute fraction of a North American market that entails hundreds of billions of dollars in transactions each year.

[91] See http://www.ferc.gov/EventCalendar/Files/20040505135203-Report-Price-Indices.pdf.

Appendix 4: Glossary of Terms[92,93]

TERM	DEFINITION
Auto ignition temperature	The lowest temperature at which a gas will ignite after an extended time of exposure (e.g., several minutes).
Basis differential	The difference in the market value of natural gas at two separate physical locations at the same point in time. Used as a proxy for the market value of pipeline transportation between those two locations at that time.[94]
British thermal unit (Btu)	A BTU is the amount of heat required to change the temperature of one pound of water by one degree Fahrenheit.
Cryogenic	Refers to low temperature and low temperature technology. There is no precise temperature for an upper boundary but -100°F is often used.
Dekatherm/Therm:	THERM: Unit of measure of heat content, equivalent to 100,000 BTU's. DEKATHERM = 10 therms or 1 million BTU's. Very roughly: 1 mcf = 1 MMBTU = 1 Dth
Density	A description of *substance* by measurement of its volume to weight ratio.
Explosion	The sudden release or creation of pressure and generation of high temperature as a result of a rapid change in chemical state (usually burning), or a mechanical failure.
Fahrenheit degrees (F)	A temperature scale according to which water boils at 212 and freezes at 32 Fahrenheit degrees. Convert to Centigrade degrees (C) by the following formula: (F-32)/1.8= C.
Flammability limit	Of a fuel is the concentration of fuel (by volume) that must be present in air for an ignition to occur when an ignition source is present.
Hedging	Defined as the purchase or sale of a futures or option contract as a temporary substitute for a cash transaction to be made at a later date. It is a strategy designed to reduce investment risk.

92 Phillips Petroleum Company, http://www.phillips66.com/lng/LNGglossary.htm.
93 Poten & Partners, http://www.poten.com/?URL=ut_glossary.asp.
94 AllEnergy Gas & Electric Marketing Company, L.L.C., http://www.allenergy.com/natural_gas/ngglossary.html.

TERM	DEFINITION
Higher heating value (HHV)	HHV - higher heating value (also: gross calorific value): the heat content of fuels which could be gained by complete combustion and condensation of water vapor.
Impoundment	Spill control for tank content designed to limit the liquid travel in case of release. May also refer to spill control for LNG piping or transfer operations.
Middle distillates	Products heavier than motor gasoline/naphtha and lighter than residual fuel oil. This range includes heating oil, diesel, kerosene, and jet *fuel*.
Mole percent	Mole is a short form of molecular weight. Mole fraction or mole percent is the number of moles of a component of a mixture divided by the total number of moles in the mixture.
MTPA	Million Tonnes per Annum. Tonnes or Metric Ton is approximately 2.47 cubic meters of LNG.
Open access	A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power or natural gas from one point to another on a nondiscriminatory basis for a fee.
Peak shaving LNG Facility	A facility for both storing and vaporizing LNG intended to operate on an intermittent basis to meet relatively short term peak gas demands. A peak shaving facility may also have liquefaction capacity, which is usually quite small compared to vaporization capacity at such facility.
Risk and hazard	Risk and hazard are not the same. Risk means the realization of potential damage, injury or loss; hazard means a condition with potential for initiating an incident or incident.
Stranded gas	Gas that is not near a customer and therefore does not justify the construction of a pipeline.
Sweetening	Processing to remove sulfur. Hydrodesulphurization, for instance, can produce sweet catalytic cracker materials useful for the production of fuels and chemicals. Caustic washing can sweeten sour natural gasolines to make them suitable for motor gasoline blending.

Appendix 5: Conversion Table

Natural gas and LNG Conversions	**To** billion cubic meters NG	billion cubic feet NG	million tonnes oil equivalent	million tonnes LNG	trillion British thermal units	million barrels oil equivalent
From	**Multiply by**					
1 billion cubic meters NG	1	35.3	0.90	0.73	36	6.29
1 billion cubic feet NG	0.028	1	0.026	0.021	1.03	0.18
1 million tonnes oil equivalent	1.111	39.2	1	0.805	40.4	7.33
1 million tonnes LNG	1.38	48.7	1.23	1	52.0	8.68
1 trillion British thermal units	0.028	0.98	0.025	0.02	1	0.17
1 million barrels oil equivalent	0.16	5.61	0.14	0.12	5.8	1

***Crude oil**	**To convert:** tonnes (metric)	kilolitres	barrels	U.S. gallons	tonnes/ year
From	**Multiply by**				
Tonnes (metric)	1	1.165	7.33	307.86	–
Kilolitres	0.8581	1	6.2898	264.17	–
Barrels	0.1364	0.159	1	42	–
U.S. gallons	0.00325	0.0038	0.0238	1	–
Barrels/day	–	–	–	–	49.8

*Based on worldwide average gravity.

Petroleum Products	**To convert:** barrels to tonnes	tonnes to barrels	kilolitres to tonnes	tonnes to kilolitres
	Multiply by			
LPG	0.086	11.6	0.542	1.844
Gasoline	0.118	8.5	0.740	1.351
Distillate fuel oil	0.133	7.5	0.839	1.192
Residual fuel oil	0.149	6.7	0.939	1.065

Example: To convert FROM 1 million tons of LNG TO billion cubic feet of natural gas, multiply by 48.7 (100 million tons of LNG equals roughly 5000 billion cubic feet of natural gas).

Units	Calorific equivalents	
1 metric tonne = 2204.62 lb.	One tonne of oil equivalent equals approximately:	
= 1.1023 short tons	Heat units	10 million kilocalories
1 kilolitre = 6.2898 barrels		42 gigajoules
1 kilolitre = 1 cubic meter		40 million BTU
1 kilocalorie (kcal) = 4.187 kJ = 3.968 BTU	Solid fuels	1.5 tonnes of hard coal
1 kilojoule (kJ) = 0.239 kcal = 0.948 BTU		3 tonnes of lignite
1 British thermal unit (BTU) = 0.252 kcal = 1.055 kJ	Gaseous fuels	See Natural gas and LNG table
1 kilowatt-hour (kWh) = 860 kcal = 3600 kJ = 3412 BTU	Electricity	12 megawatt-hours
	One million tonnes of oil produces about 4500 gigawatt-hours (=4.5 terawatt hours) of electricity in a modern power station.	

The conversion factors above are taken from *BP Statistical Review of World Energy 2003*, which is available athttp://www.bp.com/centres/energy/definitions/units.asp.