THE INGAA FOUNDATION, INC.

An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market:

Adverse Consequences of Delays in the Construction of Natural Gas Infrastructure

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EXECUTIVE SUMMARY

The North American natural gas industry is facing a critical period over the next 10 to 15 years. Since 2000, the balance between natural gas supply and demand has tightened substantially. A number of important events have occurred recently in natural gas markets contributing to the tightening including:

- A decline of excess natural gas productive capacity or elimination of the "gas bubble".
- The construction of over 200 GWs of gas-fired generation since 1999 with limited amounts of alternative fuel capability (oil backup),
- A rebound in the U.S. economy in 2003 after negative and slow growth in 2001 and 2002.

The objectives of this study are to examine infrastructure requirements with a focus on pipeline transmission capacity, storage capacity, and LNG terminal capacity. The study is conducted in the context of the changes in market fundamentals that have occurred since the INGAA Foundation published its studies of North American pipeline and storage infrastructure requirements in 1999 and in 2001.[1] As in the previous studies, natural gas supply and demand requirements are examined as well as a detailed analysis of pipeline transmission and storage capacity requirements. For this study, a new element is considered. In recent years, a number of natural gas infrastructure

[1] In January 1999, the INGAA Foundation published ***Pipeline and Storage Infrastructure for a 30 Tcf Market,*** the first in a series of studies examining the opportunities and challenges facing the natural gas industry in serving the growing natural gas market. In 2001, an update to the original study was published examining infrastructure requirements to 2015.

projects have faced intense opposition from a number of disparate groups. There has been a ten-fold increase in protests and interventions[2] in recent pipeline projects compared to a decade ago despite the significant progress that has been made to minimize both the temporary effects of construction and permanent environmental effects along the pipeline right-of-way. The result of this opposition to the construction of pipeline infrastructure is a risk that economically justified projects could be delayed – or not completed at all. This study will focus on the consequences of delay in the construction of needed infrastructure.

Natural Gas Supply and Demand Balance

From 1998 through 2003, gas consumption as reported by EIA and industry analysts has been essentially flat at 22 to 23 Tcf. Natural gas consumption in the United States for the year 2003 was 22.4 trillion cubic feet.[3] Over this period, natural gas supplies available to the United States has not grown in a manner that would allow for increases in gas consumption. At the same time, the underlying drivers for gas consumption – including a rapidly increasing need for gas fired electricity generation – have continued. Extended periods of high gas prices and increases in price volatility have been a direct result of the lack of development of new sources of gas supply sufficient to meet the market's desire for more natural gas.

EEA anticipates that U.S. natural gas consumption should approach 30 Tcf by the end of the next decade if the supply of gas is developed. But if this growth in consumption is to occur, large amounts of infrastructure including pipeline capacity, storage capacity, and LNG terminal capacity must be built in the United States and Canada.

While gas produced in traditional basins such as the mid-continent, onshore Louisiana and the shallow waters of the Gulf of Mexico will continue to be important sources of supply, by themselves they will not be sufficient to satisfy growing demand over the next

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2 FERC Office of Energy Projects reported project interventions.
3 EIA Natural Gas Annual

two decades. To meet a growing demand, gas from "frontier regions" will also need to be developed. These frontier supplies include the deepwater offshore in the Gulf of Mexico, unconventional gas in the U.S. and Canadian Rockies, Arctic gas, Eastern Canadian gas and large volumes of LNG. The development of these resources will require large capital commitments and the construction of major infrastructure projects. If the infrastructure required that is to provide growing supplies of natural gas from frontier regions is not constructed, tremendous price pressure leading to prices well above today's levels would develop in order to restrict demand growth.

The analysis conducted for this study concludes that these gas supply sources needed to satisfy a market demand of 30 Tcf are economic to develop at prices that will allow gas demand to continue to grow. These supply sources include both North American production and liquefied natural gas (LNG). This is an extremely important conclusion for energy policy. Coordinated efforts among industry, Government, environmentalists, and consumer advocates are needed to allow these projects to be built and thereby protect consumers and the economy.

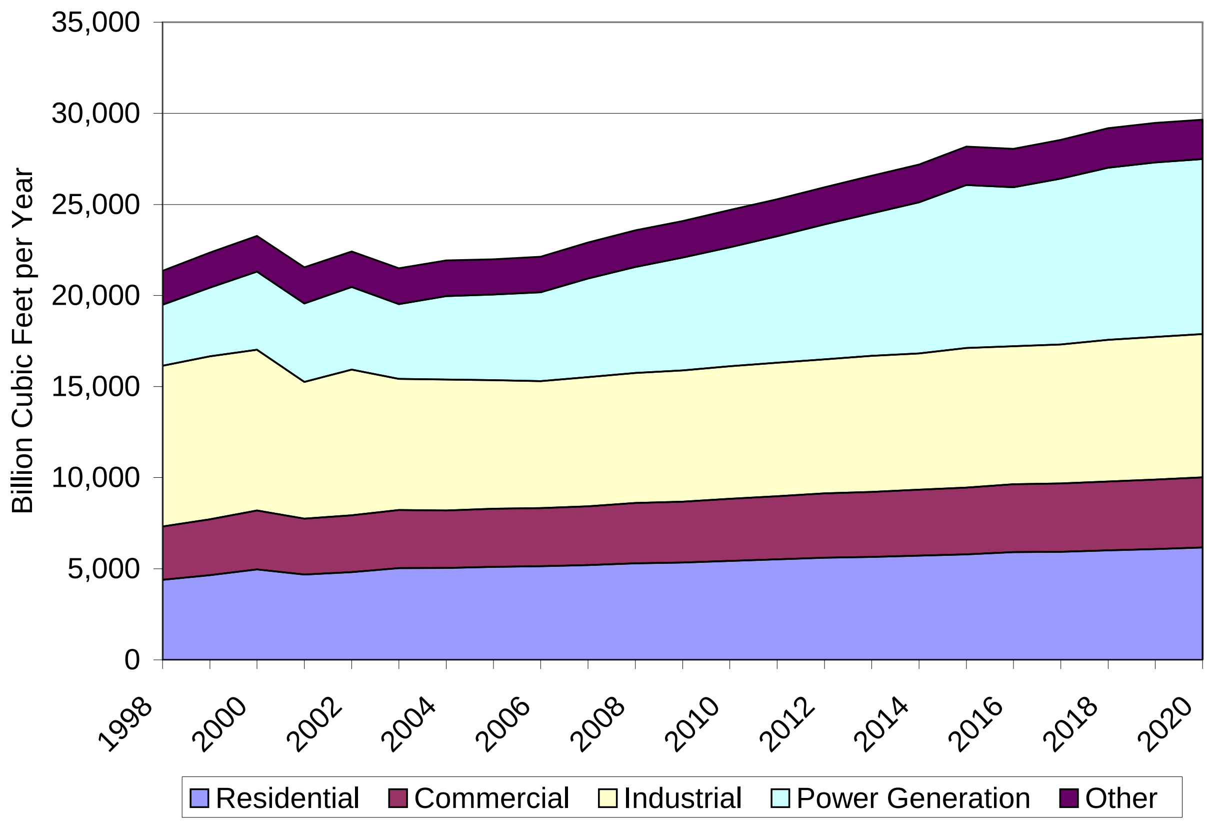
The EEA Base Case used for this study assumes that natural gas supply and infrastructure that is economic is developed. If, however, government policy and public opposition to the construction of the required infrastructure prevent the facilities from being built, gas supplies will be unable to grow to meet market demand. As a result, there could be tremendous pressure on gas prices that could hinder economic growth and the competitiveness of U.S. industry.

Natural Gas Demand

The EEA Base Case forecasts U.S. consumption to grow to essentially 30 Tcf or 29.7 Tcf by 2020, an increase of 38% or 1.9% per year (Figure 1-1). All sectors of the economy, residential, commercial, industrial, and power generation contribute to this growth. However, the power generation sector contributes well over half of the total increment. Importantly, much of the increase will come from increased utilization of generation capacity that has already been built.

The growth in power generation gas use changes the profile of natural gas demand and therefore the utilization of pipeline capacity. While natural gas use in most markets will remain highest in the winter heating season, a new form of "gas on gas" competition has been created. During the summer, much of the pipeline infrastructure must be used to inject gas into storage. Summer electric generation requirements compete for space in the pipeline with gas destined for storage injection and in the future, the competition will become more intense. Spare seasonal pipeline capacity will not be available unless incremental pipeline infrastructure is constructed.

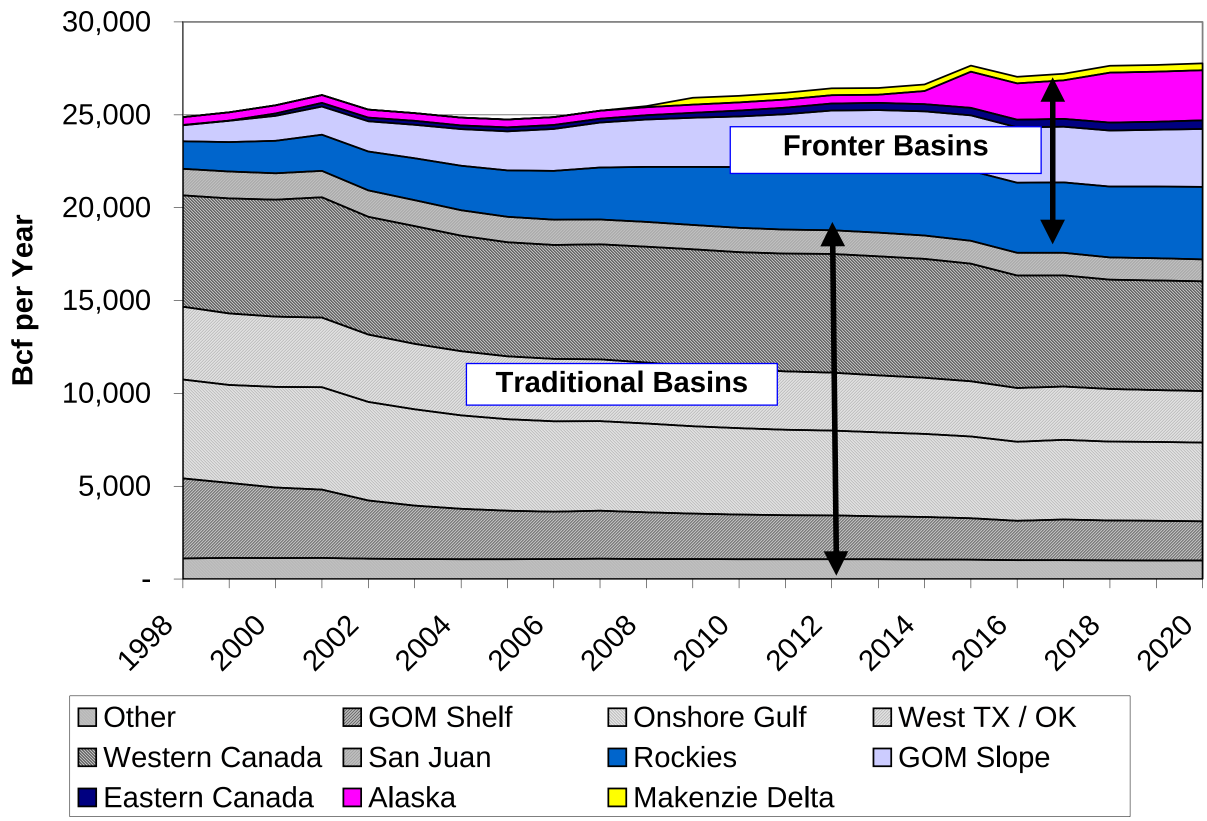
Figure 1-1
U.S. Natural Gas Demand 1998 – 2020



Natural Gas Supply

Natural gas supply from multiple sources will have to grow to meet the projected 30 Tcf U.S. market by the end of the next decade. Most industry analysts, including EEA, believe that U.S. and Canadian natural gas production from traditional basins is in decline. Production from Western Canada, West Texas and Oklahoma, the Onshore Gulf of Mexico, the Gulf of Mexico Shelf, and the San Juan Basin is approximately 19.3 Tcf per year and currently accounts for 80% of the production in United States and Canada. While production from these regions will still be an important part of the supply portfolio through the next decade, production is forecast to decline in both absolute terms and market share. By 2020, volumes from traditional basins are anticipated to decline over 3 Tcf per year to 16.2 Tcf per year, which will only be 61% of North American production (Figure 1-2).

Figure 1-2
North American Natural Gas Production by Region[1]



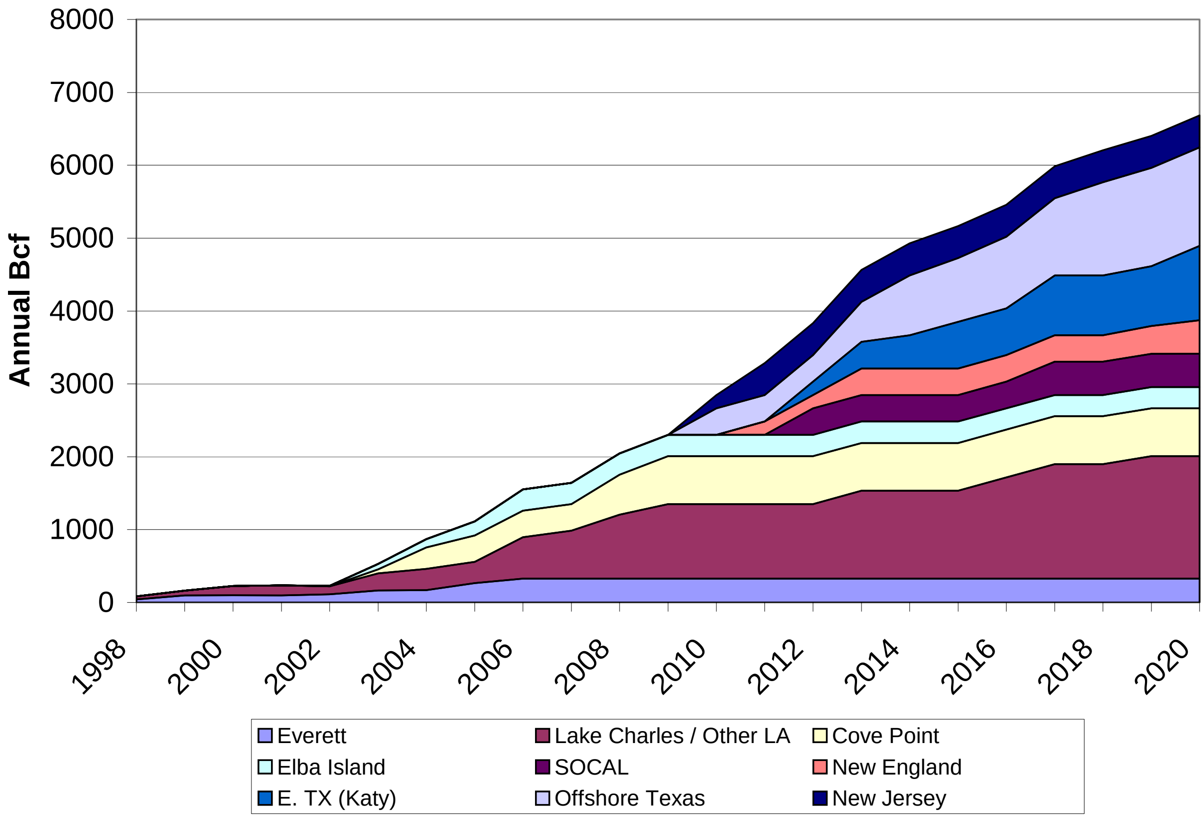
[1]Including gas produced and consumed in Canada but excludes Mexico

Hence, much of the growth of the gas market over the next 20 years must be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets in North America. Frontier basins in the arctic, such as Alaska and the Mackenzie Delta, new offshore regions, such as the Gulf of Mexico Slope and Offshore Eastern Canada, and underdeveloped domestic areas such as the Northern Rockies all will be needed to serve U.S. Demand by 2020.

LNG imports must also play a key role. U.S. LNG imports for 2002 totaled 229 Bcf. Imports for 2003 doubled the previous year at 475 Bcf. By 2020, U.S. LNG imports could be over 6,600 Bcf per year, nearly a thirty-fold increase from 2002. Figure 1-3 presents the forecast of the amount and location of imports and exports of LNG needed.

LNG is competitive with North American production at prices ranging from $3.50 to $4.00 per Mcf depending upon the distance that the LNG travel from the liquefaction plant to the import terminal. Imported LNG, in large part, becomes an economically viable energy supply because of the low cost of developing and producing abundant stranded gas resource located throughout the world.

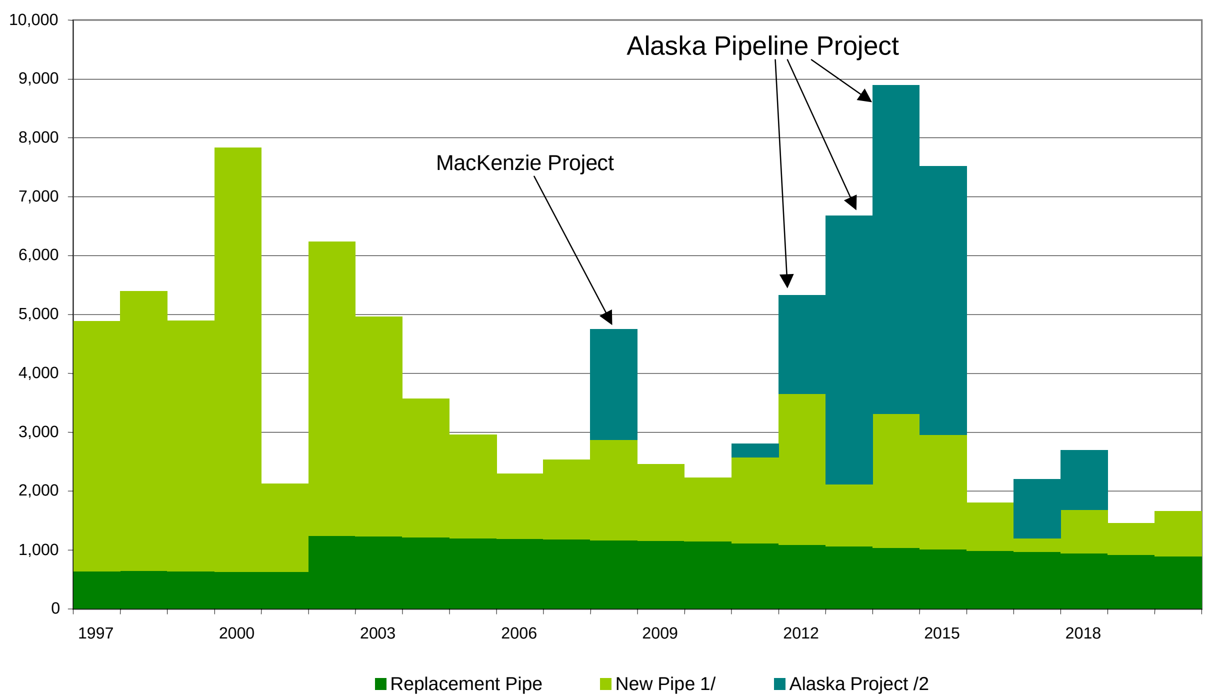
Figure 1-3
U.S. LNG Imports (Bcf / Year)



Gas Pipeline and Storage Infrastructure Requirements

Of course, to bring gas from the new supply regions and from new LNG terminals, pipeline infrastructure will have to be built. If the U.S. market is to satisfy demand in an efficient manner by the end of the next decade, significant pipeline and storage infrastructure investment (approximately $61 billion in constant 2003 dollars) must be made in both the U.S. and Canada (Figure 1-4). Approximately $19 billion of investment will be needed for replacement of current pipe simply to maintain existing pipeline capacity. Nearly $42 billion will be needed for new pipeline and storage projects. Of that, $18 billion will be associated with the Alaskan and MacKenzie Delta projects to access need supplies of arctic gas.

Figure 1-4
North American Pipeline Capital Expenditures
Millions of 2003 Dollars



/1 Includes estimates for new transmission pipe, production plant hookup, cost for new underground storage, and power plant connection costs.

/2 Includes cost of new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline, but excludes cost of gas processing plants in Alaska and natural gas liquids extraction plants in western Canada.

Gas Market Dynamics and the Consequences of Delays in Infrastructure Construction

Since 1999, the natural gas market events identified above have created a market environment that increased natural gas prices and gas price volatility. The potential magnitude for these effects first became evident in early 2000. In the winter heating seasons of 2000-01 and 2002-03, gas prices "spiked" to levels that had previously seemed unimaginable.[4] The increase in prices and in price volatility occurred because there was no "unutilized" capacity to deliver additional supplies of gas to the market when weather, economic activity, and increased power generation use of gas increased demand. The supply/demand imbalances became too large to be moderated by the behavior of customers who could easily respond to changing price conditions. As a result, large and rapid increases in gas prices occurred.

Once production and storage approach their physical limits to deliverability, price increases do not result in an immediate increase in the quantity of gas that can be delivered to consumers. New sources of gas, either from production or from LNG imports, must be developed along with storage capacity that enables the delivery of gas to match the customer's load profile. Similarly, as pipeline transmission capacity limits are reached, increases in the market value of pipeline transmission – the basis – will not result in an immediate increase in the amount of gas that can be delivered. The lead-time associated with new pipeline capacity does not allow for an instantaneous supply response when all of the capacity is being utilized. Once capacity is reached, available supply changes very little, regardless of price.

As a result of these market fundamentals, delays in the construction of natural gas infrastructure can be costly to natural gas consumers and to the stability of North American energy markets. To examine the consumer cost impacts, an Alternative Scenario to the EEA Base Case that assumes that all pipeline and LNG import terminal

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4 The 2001-02 heating season did not experience a natural gas price spike because of unusually warm weather that reduced gas demand for space heating.

projects not already under construction will be delayed an additional two years was constructed.

Using the Henry Hub price as a measure of the impact on gas prices, a two-year delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $0.78 per MMBtu from 2005 – 2020, $0.62 per MMBtu in constant 2003 dollars (Table 1-1). Price effects will be immediate and lasting throughout the forecast period. The only year where there is a relatively lower gas price than the EEA Base Case corresponds to the year after the initial Alaskan pipeline project in the Alternative Scenario.

Table 1-1
Natural Gas Price Effects of a Two-year Delay in Pipeline and LNG Terminal Construction

Average Henry Hub Price Nominal $ per MMBtu

Time Period	Base Case	Two-Year Infrastructure Delay	Price Increase
2005-2010	$5.15	$5.89	$0.75
2010-2020	$5.95	$6.75	$0.80
2005-2020	$5.65	$6.43	$0.78

Average Henry Hub Price Real 2003$ per MMBtu

Time Period	EEA Base Case	Two-Year Infrastructure Delay	Price Increase
2005-2010	$4.49	$5.15	$0.66
2010-2020	$4.24	$4.84	$0.60
2005-2020	$4.33	$4.95	$0.62

In total, a two-year delay in natural gas infrastructure construction will cost U.S. gas consumers in excess of $200 billion (in constant $2003) by 2020. Higher gas costs will be seen in all parts of the country. Only in the Northern Rockies, (Colorado, Wyoming, and Utah) will there be a temporary initial decline in natural gas prices and thus lower consumer costs. This is due to supplies being trapped in the region by capacity "bottlenecks" to moving gas out of the region. However the reduction in prices before 2010 are more than offset by increases 2011 – 2020.

Findings and Recommendations to Prevent Delays in Infrastructure Construction

In order to reduce or eliminate the risk that there will be delays in the development of natural gas infrastructure costing consumers billions of dollars, four broad areas must be addressed. First, regulators at the state and federal level should consider actions that attract capital to pipeline and storage projects. In particular, state utility regulators should conduct a review of existing rules and policies that discourage state regulated local distribution companies from entering into the long-term capacity contracts for transportation and storage that are necessary to underpin new infrastructure projects. Current state regulation often inhibits LDCs from entering into long-term contracts either actively – in the name of increasing the competitiveness of third party marketers – or implicitly through the risk of retroactive prudence review that could disallow gas capacity costs. State regulation should recognize the public benefit of capacity into a market and create a cost recovery mechanism that promotes the construction of sufficient facilities to allow for incremental supplies of gas to be delivered during peak demand periods. In addition, federal and state regulators should consider electricity resource planning that reflects the reliability benefits of firm pipeline and storage capacity to gas fired generation as well as alternative fuel capability.

Second, the gas industry should work with state and local officials including state economic development offices to ensure that all of the societal, employment, and consumer cost benefits of a pipeline, storage, or LNG terminal project are presented during the process of evaluating a proposed project. As part of this, public education and outreach efforts should include information regarding details of the construction process, the ultimate (post construction) impacts on the environment and safety as well as the ongoing direct and indirect benefits of construction.

Third, federal and state regulators should conduct regional analysis to identify the requirements of multi-state regions. While FERC currently conducts such reviews, the impact of these analyses could be enhanced by a process that develops additional "ownership or buy-in" of the conclusions within state and local governments. These regional analyses should explicitly consider the impact on consumers and economic development of a decision to prohibit or delay infrastructure development.

These regional analyses should be incorporated in federal, state, and local permitting proceedings. These permitting proceedings must reflect the consequences of a refusal to allow construction to the general population. The approach taken in state and local proceedings should reflect a balance between the local impact and the impacts of the decisions on citizens in surrounding jurisdictions.

Fourth, homeland security and safety concerns, particularly regarding LNG, must be met with a balanced and informed evaluation of risk. There are many elements of modern life that present manageable risk but almost none that can be described as risk-free. All appropriate actions to ensure safety and security should be required. However, to the extent that there is any residual risk that cannot be eliminated, that risk should be evaluated in term of the overall cost to citizens and economic security of a failure to build natural gas infrastructure that is required to meet growing energy demand.

2
INTRODUCTION

In January 1999, the INGAA Foundation published ***Pipeline and Storage Infrastructure for a 30 Tcf Market,*** the first in a series of studies examining the opportunities and challenges facing the natural gas industry in serving the growing natural gas market. In 2001, Energy and Environmental Analysis, Inc. (EEA) provided an update to the study in which we estimated future natural gas infrastructure requirements for a 30 Tcf U.S. market by 2015. The gas industry used that study to highlight the importance of new pipeline and storage capacity in achieving the economic and environmental benefits of increased gas consumption. Both studies found that serving a 30 Tcf market was economically feasible. However, the studies concluded that all segments of the gas industry would face challenges in growing the market.

In this study, EEA updates projected natural gas demand and estimated future natural gas infrastructure requirements for current and expected market conditions[5]. In addition, this study focuses on the adverse economic, environmental, and consumer cost consequences of a failure to site, finance and construct the infrastructure needed to supply growing natural gas demand.

A number of important events have occurred recently in natural gas markets which include:

- Decline of excess natural gas productive capacity or elimination of the "gas bubble".

[5] EEA's Gas Market Data and Forecasting System (GMDFS), a nationally recognized modeling and market analysis system for the North American gas market, was used to obtain the results presented in this report. The GMDFS is a full supply/demand equilibrium model of the North American gas market. The

- The construction of over 200 GWs of gas-fired generation since 1999 with limited amounts of alternative fuel capability (oil backup),

- An increase in natural gas prices and volatility beginning in early 2000 including winter price spikes in heating seasons 2000-01 and 2002-03 (the 2001-02 heating season was unusually warm).

- A rebound in the U.S. economy in 2003 after negative and slow growth in 2001 and 2002.

The most commonly cited natural gas demand forecasts in the industry have been revised downward from forecasts that were available during the 2001 study (Table 2-1). With the exception of the Energy Ventures Analysis, Inc.'s forecast of 31.1 Tcf, most analysts, including EEA, no longer predict a U.S. 30 Tcf natural gas market by 2015. The current EEA Base Case, used for this study, projects that U.S. consumption will reach 30 Tcf by 2020 or very shortly thereafter.

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model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Table 2-1
Natural Gas Consumption Forecasts
as Published in the 2003 Annual Energy Outlook[6]

	2002	EEA Base Case	EIA Annual Energy Outlook	GII	NPC Reactive Path	NPC Balanced Future	EVA	PIRA	DB
				2015 Consumption in Tcf					
Natural Gas Consumption	22.78	28.18	28.03	27.88	26.67	26.30	31.11	26.58	26.78
Residential	4.92	5.80	5.68	5.41	5.75	5.48	5.58	5.06	5.97
Commercial	3.12	3.66	3.62	3.35	3.77	3.80	3.77	3.41	4.06
Industrial	7.23	7.67	8.87	8.53	7.21	7.41	7.67	6.53	8.31
Electricity generators	5.55	8.94	7.64	8.62	7.77	7.48	11.73	9.38	6.45
Other	1.96	2.11	2.22	1.98	2.16	2.12	2.36	2.20	2.00
				2025 Consumption in Tcf					
Natural Gas Consumption		n/a	31.41	30.75	27.62	26.62	35.89	n/a	29.66
Residential		n/a	6.09	5.87	6.17	5.82	5.94	n/a	6.66
Commercial		n/a	4.04	3.62	4.09	4.18	4.16	n/a	4.78
Industrial		n/a	10.29	9.35	7.10	7.38	8.57	n/a	9.18
Electricity generators		n/a	8.39	9.83	8.18	7.24	14.50	n/a	6.78
Other		n/a	2.59	2.08	2.08	2.01	2.72	n/a	2.27

In all of these forecasts, consumption from gas-fired power generation shows the largest absolute growth and largest percentage growth. It is not surprising that the estimates in natural gas consumption in the power sector are the principal source of differences among the projections. In a comparison of gas market forecasts published by the Energy Information Administration's 2002 estimates for consumption as a base, growth in the power sector to 2015 could be as low as 1.2% as predicted by the Deutsche Bank AG, or as high as 5.9% as in the Energy Ventures Analysis, Inc.'s forecast.

[6] **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (Apr 2004). Other sources as stated in the Energy Information Administration (**EIA**) Annual Energy Outlook 2004: **GII:** Global Insight, Inc., *Spring/Summer 2003 U.S. Energy Outlook* (July 2002). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (July 2003). **NPC:** National Petroleum Council, *Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy*, Volume I, Summary of Findings and Recommendations (Washington, DC, September 2003), web site www.npc.org/NG_Volume_1.pdf. **PIRA:** PIRA Energy Group (October 2003). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 3, 2003.

Objectives of This Report

For this report, the INGAA Foundation has again contracted Energy and Environmental Analysis, Inc. to conduct an analysis of the requirements and challenges of meeting the growing demand for natural gas. To properly evaluate the natural gas market and the outlook for gas transportation and storage infrastructure, the study:

- Creates a Base Case of gas market projections of natural gas in light of current developments in the market. The projection of the market has been extended five years beyond the previous study to 2020.

- Projects the most likely sources of natural gas supply to be developed to meet demand and estimates the amount of LNG imports that will be necessary to supplement North American natural gas sources.

- Identifies the magnitude of the shift in the location of production from mature regions to new frontier regions.

- Estimates the need for new pipeline and storage capacity for the Base Case Scenario taking into account gas demand by sector, monthly consumption patterns and peak day requirements.

- Contrasts the Base Case scenario with an Alternative Scenario that assumes that all additional pipeline and LNG re-gasification terminal capacity, including such frontier gas projects as the Alaskan Gas Pipeline and the MacKenzie Delta Pipeline are delayed by two years. The study discusses the effect of restricted gas supply access to power plants on air emissions from the power sector. The study estimates the magnitude of job losses that would result from restricted development of gas infrastructure.

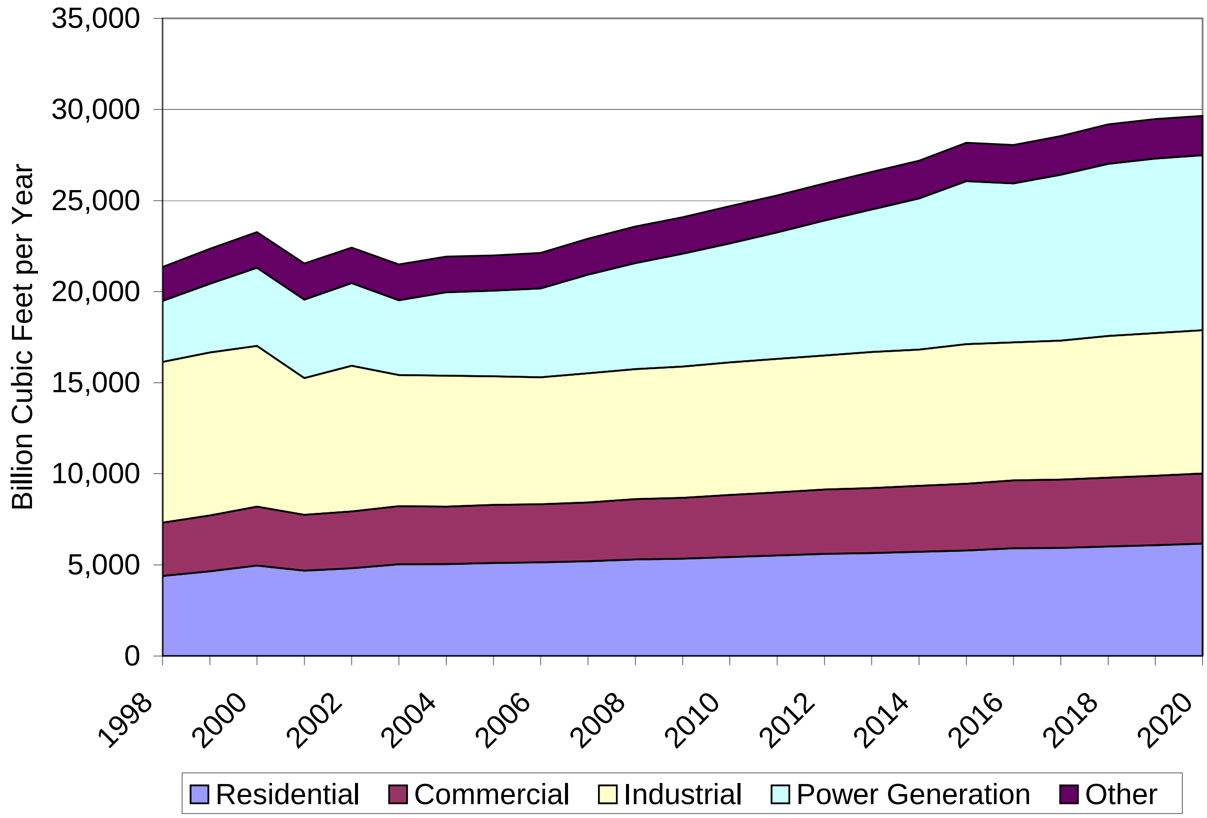
3
NATURAL GAS DEMAND

Natural gas consumption in the United States for the year 2003 was 21.5 trillion cubic feet (Table 3-1, Figure 3-1). EEA anticipates that U.S. natural gas consumption will reach 30 Tcf near the end of the next decade if the industry is allowed to construct the infrastructure needed to supply a growing market. The EEA Base Case forecasts U.S. consumption to grow to 29.7 Tcf by 2020, an increase of 38% or 1.9% per year. All sectors of the economy, residential, commercial, industrial, and power generation contribute to this growth. However, the power generation sector contributes well over half of the total increment.

Table 3-1
U.S. Natural Gas Demand
(Bcf per Year)

	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2003-2015** ***% change***	**Annual** ***% change***
Residential	5,037	5,039	5,103	5,428	5,795	6,163	22.4%	1.19%
Commercial	3,191	3,155	3,189	3,406	3,659	3,859	20.9%	1.12%
Industrial	7,196	7,188	7,057	7,286	7,667	7,855	9.2%	0.52%
Power Generation	4,107	4,586	4,707	6,530	8,941	9,610	134.0%	5.13%
Other	1,966	1,953	1,933	2,048	2,116	2,171	10.4%	0.59%
Total	**21,497**	**21,921**	**21,989**	**24,698**	**28,178**	**29,658**	38.0%	1.91%

Figure 3-1
U.S. Natural Gas Demand 1998 – 2020



Natural Gas Demand Drivers

There are several drivers pushing to increase natural gas demand. The most important among them are:

1) The pace of economic activity and growth,
2) The price and availability of alternative fuels,
3) Demand for electricity, and
4) Environmental and other regulations that might affect fuel competition, particularly in power generation market.

Economic Activity

In the short run, weather effects are the major cause of fluctuations in natural gas consumption, dwarfing the impacts of all other controlling factors. However, growth in the economy is the most significant determinant of the underlying growth in natural gas requirements in the longer term for all sectors: residential, commercial, industrial, and power generation.

Through the 1990s real U.S. GDP grew at a robust rate of over 3.2% per year. However the economy took a downturn in early 2001 and was in recession for the final three quarters of the year. After a return to modest growth of 2.0% in 2002, the economy rebounded more strongly in 2003 with a growth rate of 3.2%.

For this update of natural gas infrastructure requirements, EEA has assumed that beginning 2004, the U.S. economy will grow 2.8 percent per year and while industrial production will grow at 2.3 percent per year. These rates of economic expansion are consistent with the average rates of growth over the past 30 years rather than with the more rapid expansion of the 1990s. To the extent that economic growth is more rapid than the assumed growth rate, gas requirements in all sectors will be higher and the need for pipeline infrastructure develop would be accelerated.

Price of Alternate Fuels

Large industrial and power generation customers with dual-fuel capability can respond to natural gas price changes by switching to other fuel sources. The dual-fuel segment of the U.S. gas market is approximately 8 to 10 percent of total gas consumption. The extent of fuel switching is based upon the relationship between the gas price and the alternative fuel price (generally distillate or residual fuel oil). However, such fuel switching occurs only as long as the alternative fuel is available and the end-use facility has the necessary air emission permits.

The price of West Texas Intermediate has been trading on the spot market in excess of $30 per barrel for much of the second half of 2003 and early 2004. This equates to approximately $6.50 per MMBtu for distillate fuel oil, and $4.40 per MMBtu for residual fuel oil.

For this study, EEA has assumed that oil prices will return to more historical price levels by the beginning of 2006. West Texas Intermediate is projected to be $24 per barrel in constant $2003. This equates to a real $2003 distillate fuel price of $5.20 per MMBtu and a real residual fuel price $3.50 per MMBtu. In the industrial sector, fuel switchability in industrial boilers is assumed to stay at current levels of 5 percent of the boiler stock. Fuel switching capacity of the fleet of combined cycle and combustion turbines in the power generation sector increases from 11 percent today to 25 percent by 2020.

Electricity Demand Growth

The amount of natural gas, as well as all other fossil fuels, consumed in the power generation sector is dependent, in part, on the amount of total electricity sales. Growth in electricity sales is a key driver in determining growth in gas-fired generation. Other determinants include the relative prices among the fossil fuels, the efficiency of the various generating units, and the amount of nonfossil generation.

Electricity sales increase with growth in the U.S. economy. The income elasticity of electric sales, or the percentage growth of electricity sales per percentage growth in GDP, has been declining for decades. In the 1950s, the income elasticity was greater than 1, meaning electricity sales were growing faster than GDP. Currently, the income elasticity is approximately 0.7. For this study, EEA has assumed that the income elasticity declines to 0.65 by 2020. Implicitly, the projection assumes that the economy continues to improve the efficiency of end-use electricity applications while also continuing to expand the number and scope of electric applications. To the extent that electricity demand growth is more rapid than the assumed growth rate, the need for pipeline infrastructure construction would be accelerated.

Projected Natural Gas Demand

Residential and Commercial Sectors

Residential and commercial natural gas consumption in the United States for the year 2003 was 5.1 Tcf and 3.2 Tcf, respectively, for a total 8.3 Tcf or 39% of U.S. natural gas consumption. By 2020, these sectors will grow by an additional 1.8 Tcf or at average annual growth rates of 1.2% and 1.1% (Table 3-1).

Population growth and housing and building construction largely determine long-term growth in consumption of natural gas for the residential and commercial sectors. Other contributing factors include conservation, efficiency, and technology changes. The latter factors are mainly driven by current and anticipated natural gas prices. Consumption is more price elastic in the longer term because purchases of more efficient equipment are driven by long-term price trends.

Natural gas is anticipated to remain the fuel of choice in traditional space heating and water heating applications. In recent years, natural gas has captured more than 60 percent space heating market for the new single family homes and will continue to dominate this market in the future. The residential housing stock and the number of gas heated homes are expected to continue to grow at about 1.3 percent per year.

Industrial Sector

Industrial gas demand is critically important in any gas demand projection. U.S. industry is the largest consumer of natural gas today at 7.2 Tcf per year. The potential for growth or loss of industrial load figures prominently in any forecast. The industrial sector is probably the most complex of the sectors to assess. We believe that there will be only modest growth in the industrial sector rising to 7.9 Tcf per year by 2020 or 0.5% per year from today's levels. This level of consumption is lower than the nearly 9 Tcf that was seen in the late 1990s.

Industrial sector gas demand is comprised of four basic components: 1) boiler applications used to generate steam, 2) direct process heating applications, 3) feedstock applications, and 4) and combined heat and power or cogeneration. Industrial gas consumption is highly concentrated, with only six industries accounting for over 80 percent of industrial gas use: food, paper, chemicals, refining, primary metals, and stone, clay and glass. The chemical industry alone accounts for over one-third of industrial gas consumption, mostly in the petrochemical part of the sector.

Natural gas price spikes in 2000-01 and 2002-03 affected the U.S. industrial sector in a variety of negative ways. Some industrial facilities were shut down or temporarily idled. Ammonia producers shut down their plants, unable to compete with imports. Foundries producing at the margin also shut down. Aluminum smelters shut down in response to high gas prices and high electricity prices that were the result of the high gas prices. Markets for these end-use products were met by either U.S. firms shifting operations overseas or customers switching to foreign suppliers.

Where possible, gas users switched to distillate or residual fuel oil. Some integrated steel mills switched to fuel oil in their blast furnaces, and others shut down. Refineries opted to consume propane in place of gas, causing propane shortages in the residential sector. Several plants with lower-priced gas supply contracts sold their gas instead of using it to manufacture their own products. The result was over a one Tcf per year decline in industrial gas consumption (Table 3-2).

If relatively high gas prices persist for many years to come, as EEA's Base Case predicts, industries will be forced to revamp and improve operations (i.e., fuel switching, increased energy management activities, and installation of more efficient equipment may become prevalent). To the extent possible, some industries will pass on increased production costs to customers.

Table 3-2
Recent Natural Gas Consumption by Sector
(Bcf per Year)

Source: U.S. Energy Information Administration

	Residential	Commercial	Industrial	Power Generation	Other	Total
1998	4,520	3,009	8,320	4,588	1,808	22,246
1999	4,726	3,056	8,079	4,820	1,724	22,405
2000	4,996	3,230	8,142	5,206	1,793	23,368
2001	4,776	3,052	7,363	5,343	1,713	22,247
2002	4,909	3,181	7,203	5,672	1,688	22,653
Annual Average	**4,785**	**3,106**	**7,822**	**5,126**	**1,745**	**22,584**
% of Total	**21%**	**14%**	**35%**	**23%**	**8%**	

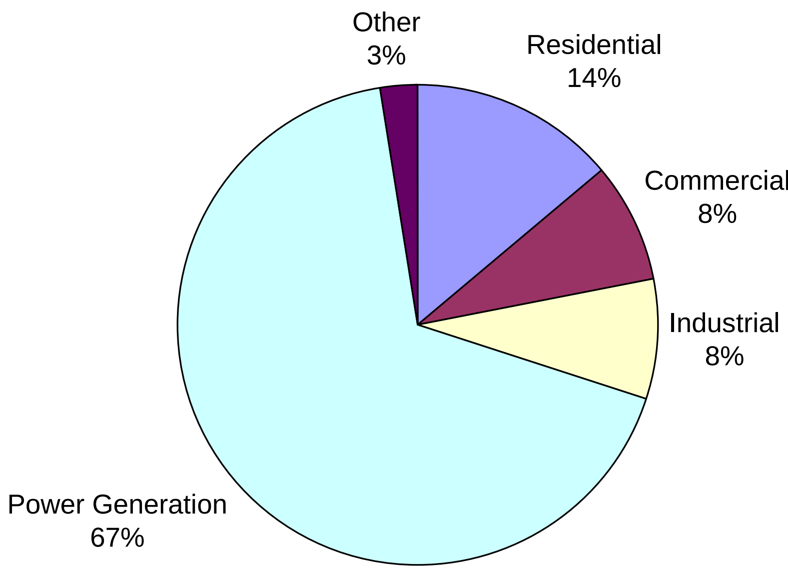
Relatively high gas prices have led to demand destruction in the industrial sector, a trend that we do not expect to continue ...

… however, gas use in power generation has been growing due to increased reliance on gas-based power generation, a trend we expect to continue.

Power Generation Sector

Power generation is the fastest growing sector for natural gas consumption in the U.S. In 2003, gas-fired generation consumed 4.1 Tcf. We predict that consumption will increase at a rate of 5.1% per year. Two-thirds of the U.S. incremental gas demand from 2003 to 2020 will come from the power sector (Figure 3-2). Sometime near the middle of the next decade, the power generation sector will surpass the industrial sector as the largest natural gas consuming portion of the economy with natural gas use more than doubling to 9.6 Tcf in 2020.

Figure 3-2
Growth in Annual Gas Demand from 2003 to 2020
8,161 Bcf per Year



The reason for the recent and continued rise of natural gas consumption in the power sector is the increase in gas-fired generating capacity. Between 1998 and 2003, over 200 Gigawatts (GW) of new capacity was built in the U.S. (Table 3-3). Of the new plants, about 10 percent have the capability to switch to oil for a limited number of hours per year, but most operate exclusively on natural gas.

Table 3-3
Lower-48 Generating Capacity

	2003	2004	2005	2010	2015	2020	*% change*
Pre 1997 Oil/Gas Capacity	202	195	190	178	163	147	-27.1%
Post 1997 CT/CC Additions	203	213	223	256	285	319	57.3%
Total Oil/Gas Capacity	405	408	414	434	448	466	15.1%
Coal	306	306	317	329	331	364	18.8%
Nuclear	97	97	97	95	95	95	-1.1%
Hydro	98	98	99	99	99	99	1.3%
Renewables and Other	7	7	10	15	26	48	592.8%
Total Capacity	**764**	**764**	**936**	**972**	**1000**	**1073**	40.4%

Power plant developers have chosen to build gas-fired plants for a variety of reasons. The initial capital cost for construction is lower for gas-fired plants than other types. The construction time is shorter and the plants are easier to permit than most other types of plants, hence, they can be built more quickly. Sulfur dioxide and particulate emissions are far lower for gas-fired plants than for coal or oil plants. And, at least until the late 1990s, natural gas appeared to be an abundant and inexpensive fuel.

The pace of construction will be slowed by the recent and anticipated increases in natural gas prices. Still, due to their advantages over other types of plants, it is generally agreed that gas-fired plants will continue to provide an increasing share of the nation's needs for electricity. We see an additional 100 GWs of gas-fired generation being built by 2020. The lead-time required to build a significant amount of new coal-fired capacity or any nuclear capacity effectively removes these options from the marketplace during the next several years. Beyond 2010, however, new electric generation capacity is projected to be more evenly split between gas and coal. We predict that approximately 60 GWs of new coal capacity will be built in the U.S. by 2020, mostly in the next decade.

Electricity sales are anticipated to grow from 3.5 trillion kWhs in 2003 to 4.8 trillion Kwhs in 2020. Increases in gas-fired generation are anticipated to account for more than half of the increase. Gas-fired generation as a percent of total generation grows from 15% in 2003 to 25% in 2020.

Regional Demand Growth

Natural gas demand is projected to grow in all regions of the country and all regions will need the infrastructure to serve growing demand (Figures 3-3, 3-4, 3-5). However, since the power generation sector is the fastest growing segment of the natural gas market, and power generation peaks with cooling load in the summer, warmer parts of the country with increasing populations will see higher proportional growth rates. The Southeast and Florida plus the Mountain and West regions, which includes Arizona and California is anticipated to grow faster than the Midwest and Plains, the Northeast, and the Gulf Coast regions.

Figure 3-3
2003 U.S. Gas Demand by Region
21,497 Bcf

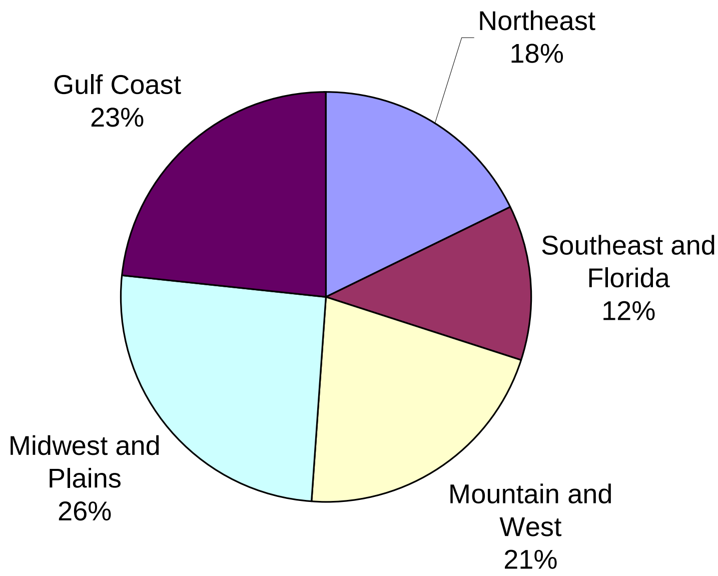


Figure 3-4
2020 U.S. Gas Demand by Region
29,658 Bcf

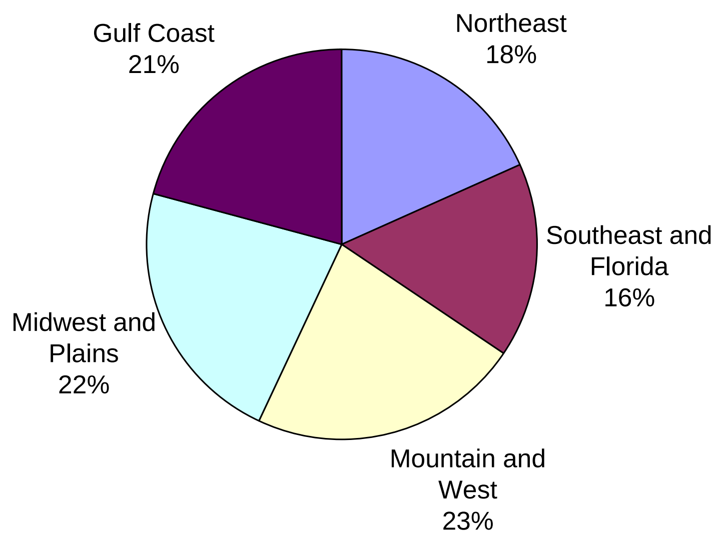
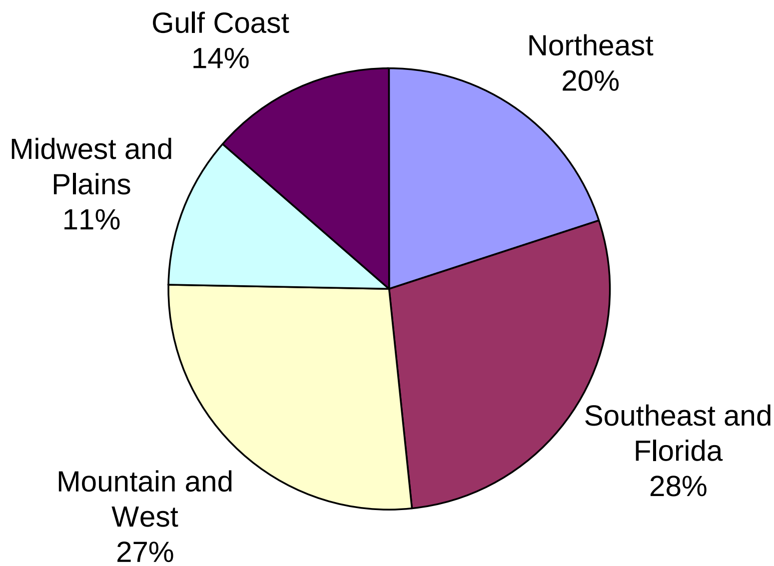


Figure 3-5
Incremental U.S. Gas Demand by Region
8,161 Bcf per Year



Seasonal Patterns of Gas Demand

Despite the fairly rapid increase in gas use for power generation, the U.S. natural gas market is and will continue to be winter peaking (Figure 3-6). The seasonality of space heating load dominates all but the southern most regions of the country. Currently, with normal weather, the U.S. demand in the peak winter month is well over 70 percent higher than the peak summer month demand. U.S. summer demand is anticipated to increase relative to winter demand. However by 2020, peak U.S. winter month demand will still be 60 percent greater than peak summer month demand. The shoulder months in spring and fall are anticipated to continue to be low gas consumption months.

Figure 3-6
U.S. Natural Gas Demand by Month
Average Bcf per Day

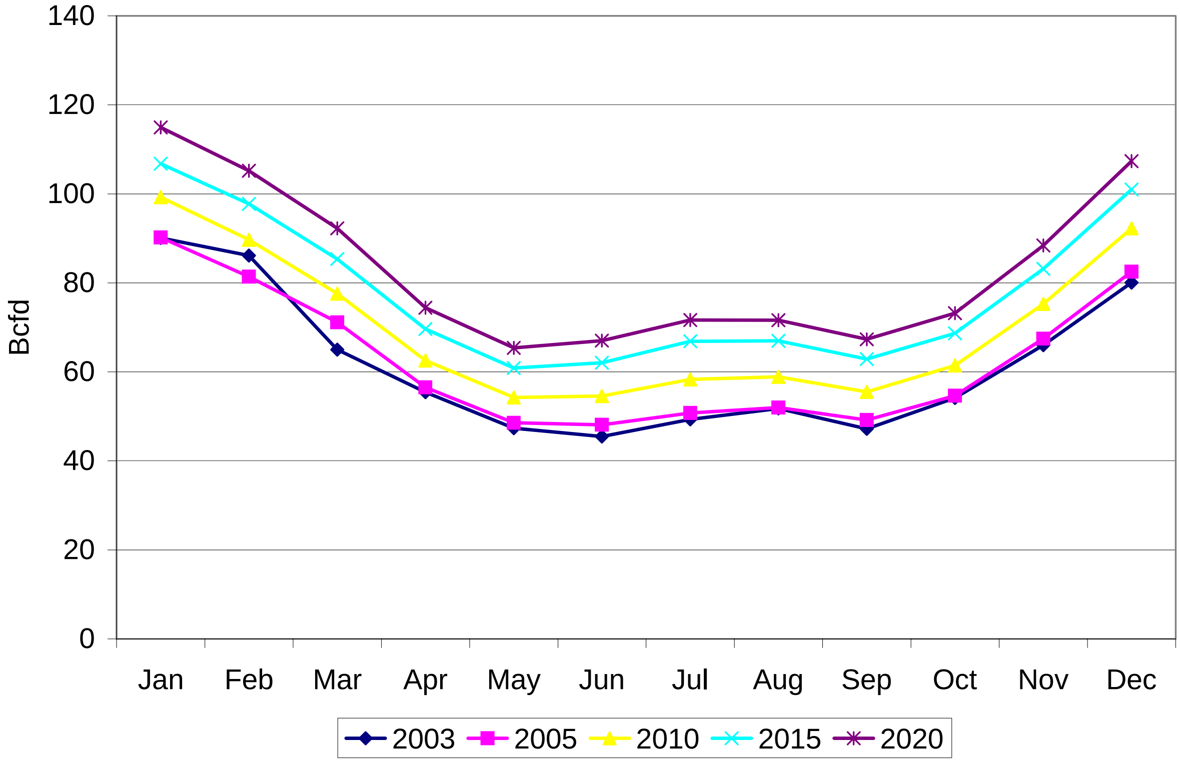
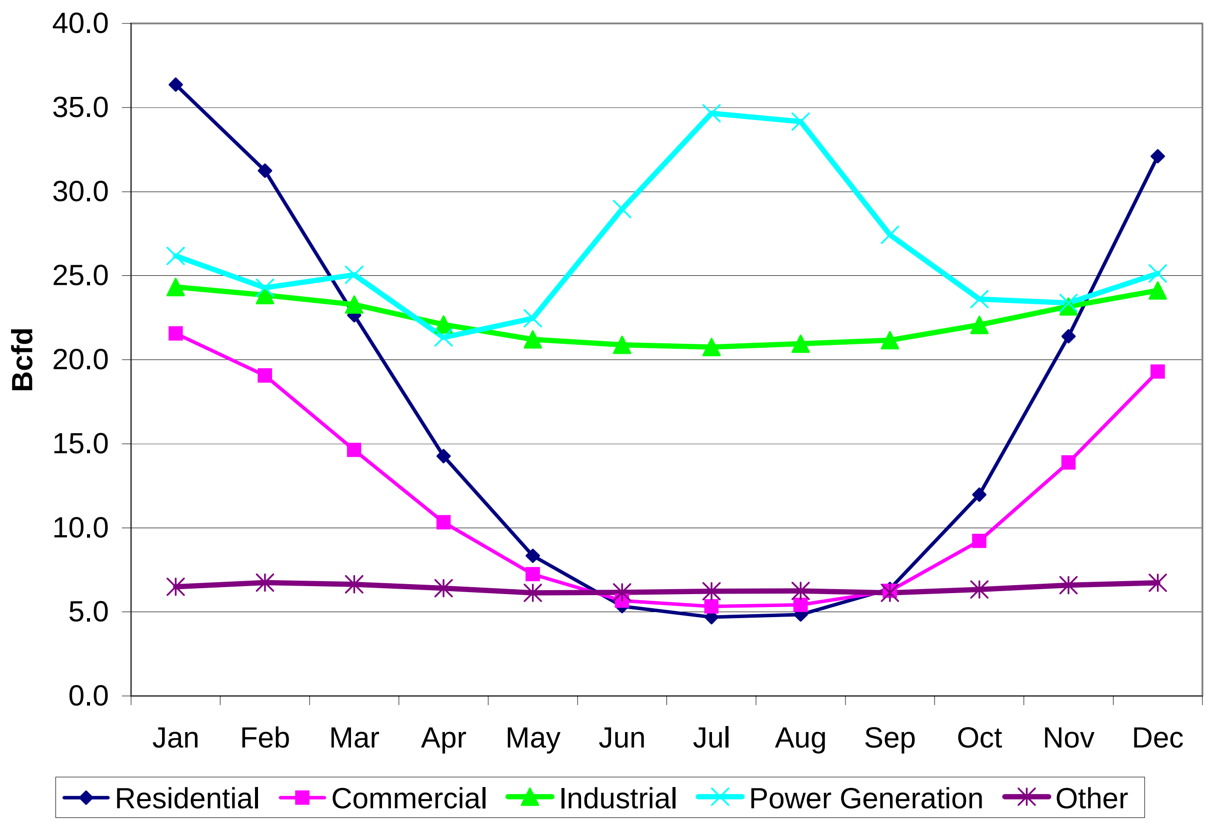


Figure 3-7 presents the anticipated monthly pattern of gas demand by end-use sector. The figure shows that most segments of the natural gas market are winter peaking. The residential market is seven times larger in the winter than in the summer while the commercial sector's winter demand is at least four times larger. Industrial demand has only slight variances between winter and summer, but still shows a modest winter peak. Only the power generation sector is counter cyclical and peaks in the summer. However, the variance between seasons is not nearly as large as the space heating sectors and therefore the U.S. market as a whole has a winter peak. It should be noted that much of the pipeline infrastructure during the summer is used to inject gas into storage. Spare seasonal pipeline capacity will not be available, and therefore incremental pipeline infrastructure will be needed to serve an increasing summer market.

Figure 3-7
2020 U.S. Natural Gas Demand by Month by Sector
Average Bcf per Day



4
GAS SUPPLY AND PRODUCTION

North American natural gas supply is diverse, with gas originating from many different sources and areas. Historically, North America has been self-reliant, and most of its gas supply has come from the U.S. Gulf Coast producing area and from the Western Canadian Sedimentary Basin. Recently, both areas have shown signs of resource depletion, shifting the focus of gas producers to different formations (generally deeper sediments) and to other areas. For example, there has been increased focus on developing gas resource located in the deeper waters of the Gulf of Mexico[7], with less emphasis on developing shallow water gas resource where most historical activity has been concentrated. LNG imports are also high on the list of potential new gas supplies for the North American gas market. In short, gas suppliers are looking to new frontiers for future supplies. Given the maturity of the North American gas resource, we expect that this new focus will continue well into the future.

North American Resource Development and Production

To date, over 1,300 trillion cubic feet (Tcf) of gas resource has been developed in North America (Table 4-1). Cumulative historical production currently stands at almost 1,100 Tcf, or over 80 percent of the total gas resource developed to date. The remainder of developed gas resource that has not yet been produced (otherwise known as proven reserves) is currently 244 Tcf.

[7] Activity has shifted out to water depths greater than 200 meters.

The Gulf Coast producing area (both onshore and offshore), the Western Canadian Sedimentary Basin, and the Rockies (Figure 4-1) are all net exporters of natural gas within North America. Collectively, these areas account for 71 percent of the proven gas reserves and 77 percent of the current gas production in North America.

The Gulf Coast producing area (both onshore and offshore) accounts for almost 70 Tcf, or about 25 percent of the proven gas reserves in North America. Not surprisingly, the area is also the most prolific production area in North America, accounting for almost 10 Tcf or 40 percent of the current gas production.

The Western Canadian Sedimentary Basin has almost 60 Tcf of proven gas reserves, accounting for slightly over 20 percent of the proven gas reserves in North America. The Western Canadian Sedimentary Basin also accounts for about one-quarter of current North American gas production.

The Rocky Mountain producing area, which includes many different producing formations and basins, has almost 50 Tcf of proven gas reserves, accounting for just under 20 percent of the proven gas reserves in North America. However, at present, the Rocky Mountains only account for 13 percent of the North American gas production. A significant amount of gas resource developed in the Rocky Mountains has been unconventional[8] gas that is produced at relatively high R/P ratios[9]. Conversely, Gulf Coast gas resource is mostly conventional gas with much lower R/P ratios and higher decline rates.

In contrast to the areas discussed above, the Eastern Interior is a net importer of gas within North America. The Eastern Interior accounts for only 14 Tcf of gas reserves or 5

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8 Includes coalbed methane, very low permeability formations, and shales.

9 R/P ratio – Natural gas reserves / annual production. The average R/P ratio for all North American gas production is just under 10. In contrast, the R/P ratio for Rocky Mountain gas is about 15. The U.S. Energy Information Administration is currently investigating why the R/P ratio for Rocky Mountain gas production is so high. The number may reflect pre-booking of resource that is thought to exist but has not yet been developed, for example, pre-booking of the extensive coalbed methane resource located in Powder River Basin.

percent of the proven reserves in North America. In addition, the region only accounts for just over 3 percent of the current North American gas production. We expect that the Eastern Interior gas markets will continue to rely on gas from other North American regions, primarily the Gulf Coast and Eastern Canada, or LNG imports for future gas supply.

Table 4-1 indicates that a significant and widespread resource remains to be developed. In total, the remaining resource could sustain today's level of North American gas production for almost 70 years, assuming it is fully developed. However, it's highly unlikely that the total gas resource will be fully developed, as only cost-effective resource is likely to be developed in the foreseeable future. EEA supply analysis indicates about 700 Tcf of gas[10] that is economic to develop at Henry Hub gas prices below $5 per MMBtu[11]. This would indicate that there is an additional 600 Tcf of non-Arctic gas that is uneconomic to develop at sustained gas prices of $5 per MMBtu.

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10 Does not include Canada Arctic and Alaska gas resource.

11 The supply curves indicate the amount of gas resource that is economic to develop through 2020 at different gas prices. In reality, it is unlikely that total amounts indicated will be developed because of constraints on drilling activity and capital constraints, among other factors. Hence, the supply curves indicate the maximum amount of resource that is likely to be developed at different gas prices.

Table 4-1
Natural Gas Resource, Reserves, and Production (Tcf)[12]
Source: Energy and Environmental Analysis, Inc.

Region	Cumulative Historical Production	(Plus) Proven Reserves	(Equals) Developed Resource	(Plus) Estimated Remaining Resource	(Equals) Total Resource		Estimated Production in 2002
Alaska	10.8	8.8	19.6	321.8	341.4		0.4
West Coast Onshore	31.9	2.6	34.5	32.6	67.1		0.3
Great Basin	1.4	1.0	2.4	4.0	6.4		0.1
Rockies	67.1	49.7	116.8	213.3	330.2		3.4
West Texas	105.4	16.4	121.8	54.2	176.0		1.7
Gulf Coast Onshore	321.5	37.5	359.0	176.5	535.5		4.9
Mid-continent	179.9	24.0	203.9	72.6	276.5		2.2
Eastern Interior	54.9	13.7	68.6	122.1	190.7		0.9
Gulf of Mexico	163.1	29.2	192.3	316.0	508.3		4.9
U.S. Pacific Offshore	2.6	0.6	3.2	1.2	4.4		0.0
WCSB	126.0	57.5	183.5	206.5	390.0		6.4
Arctic Canada	0.1	0.0	0.1	73.9	74.0		0.0
Eastern Canada Onshore	1.1	0.4	1.5	7.2	8.7		0.0
Eastern Canada Offshore	0.3	2.2	2.5	96.1	98.6		0.2
Western British Columbia	0.0	0.0	0.0	11.5	11.5		0.0
North America Total	1,066.0	243.5	1,309.7	1,709.5	3,019.1		25.4

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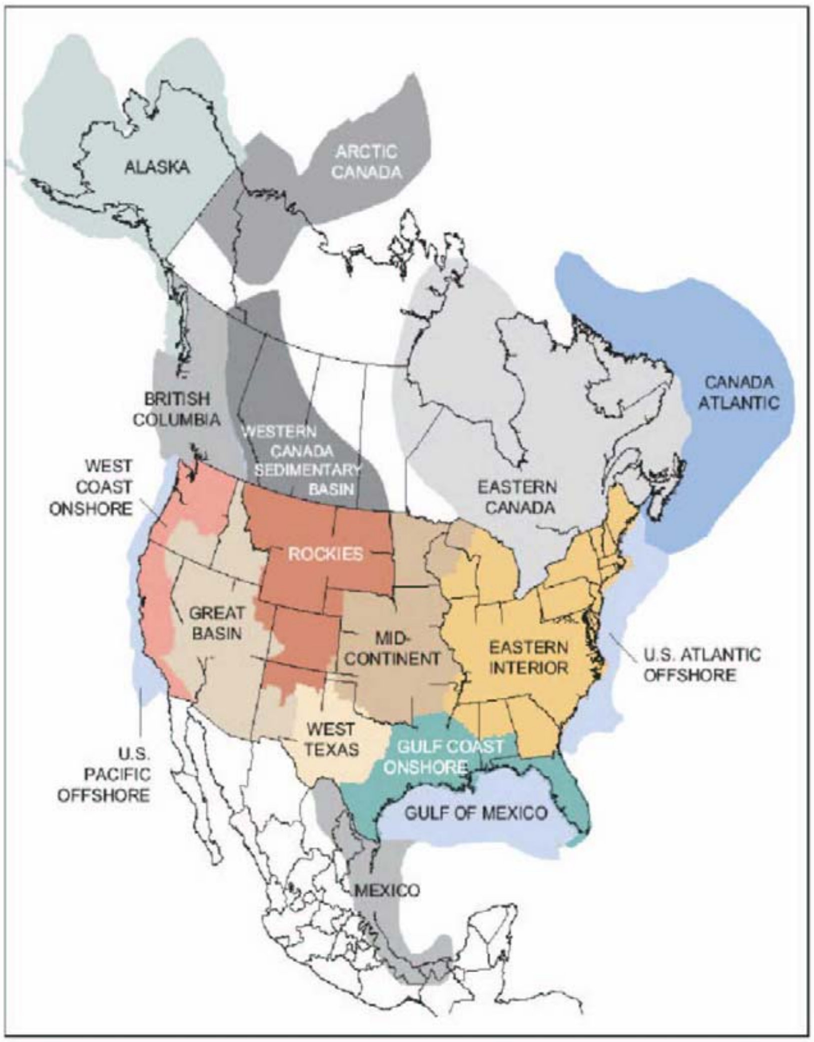
12 Unless otherwise stated, values are dry gas at the end of 2001. Resource values represent accessible and technically recoverable resource through 2020 with advancement of E&P technologies consistent with recent improvements. Does not include an estimated 180 Tcf of resource not currently accessible.

Figure 4-1
North American Production Areas

Source: U.S. National Petroleum Council



Natural gas supply from multiple sources will have to grow to meet the projected 30 Tcf U.S. market by the end of the next decade. Most industry analysts, including EEA, believe that U.S. and Canadian natural gas production from traditional basins is in decline (Figure 4-2). Production from Western Canada, West Texas and Oklahoma, the Onshore Gulf of Mexico, the Gulf of Mexico Shelf, and the San Juan Basin is approximately 19.7 Tcf per year and currently accounts for 80% of the production in North America (Figure 4-3). While production from these regions will still be an important part of the supply portfolio through the next decade, production is forecasted to decline in both absolute terms and market share. By 2020, volumes from traditional basins are anticipated to decline over 3 Tcf per year to 16.2 Tcf per year, which will only be 61% of North American production (Figure 4-4).

The declines in production from traditional supply sources are mainly due to the lack of quality drilling prospects in the areas. Already, the North American gas market is experiencing declines in some basins. Gas producers have had to work harder to develop additional deliverability. Producers are working harder in mature areas, but are developing less productive gas resources. Whether it is due to increased decline rates, lower reserves, or a higher percentage of nonconventional wells (tight sands, coal bed methane, or shale), it appears that more wells are needed just to maintain the current rate of production.

In order for production to be maintained as fields naturally deplete, more expensive formations must be completed. The wells may be in deeper formations that have higher temperatures and pressures or the gas may be sour (containing sulfur) and more corrosive, requiring additional processing. Less permeable formations may be drilled. Such wells need to be fractured down hole[13] in order to be produced economically. In general, most of the large natural gas reservoirs have been found. Future fields will be smaller and need to be more numerous to maintain the same amount of production.

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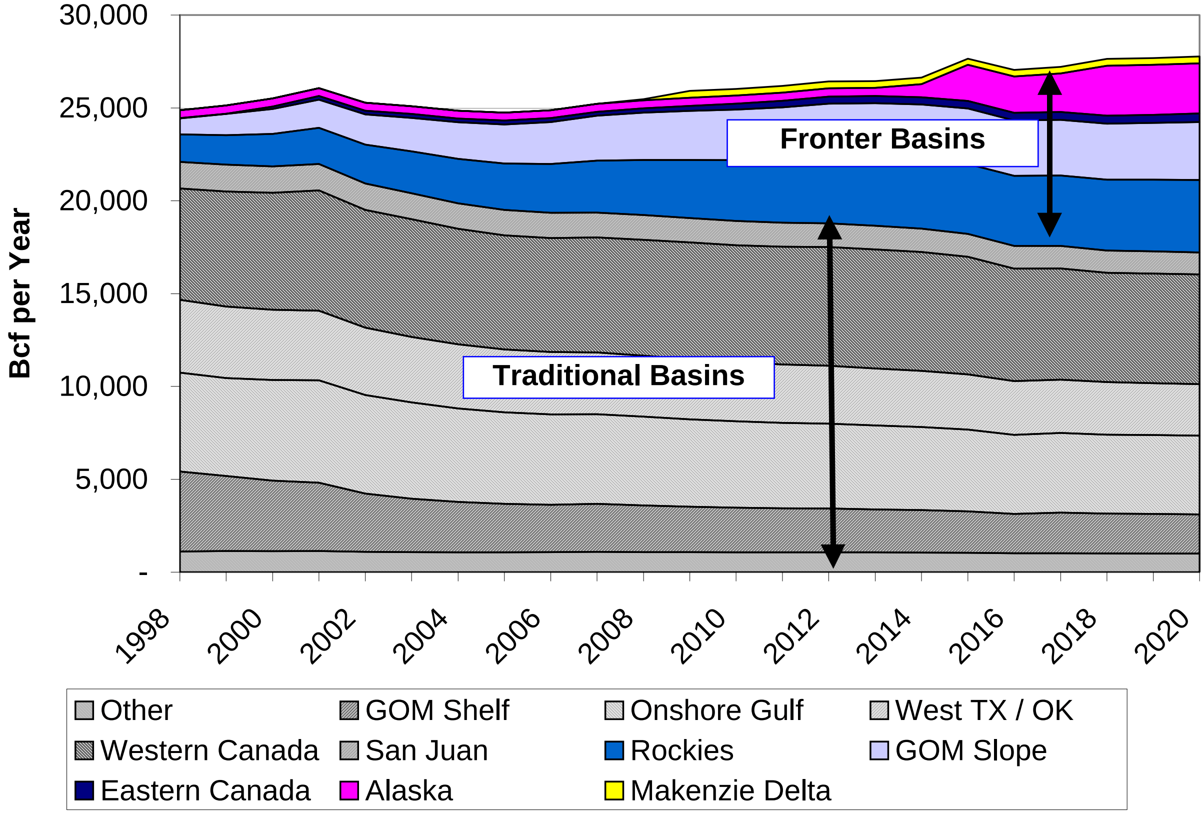
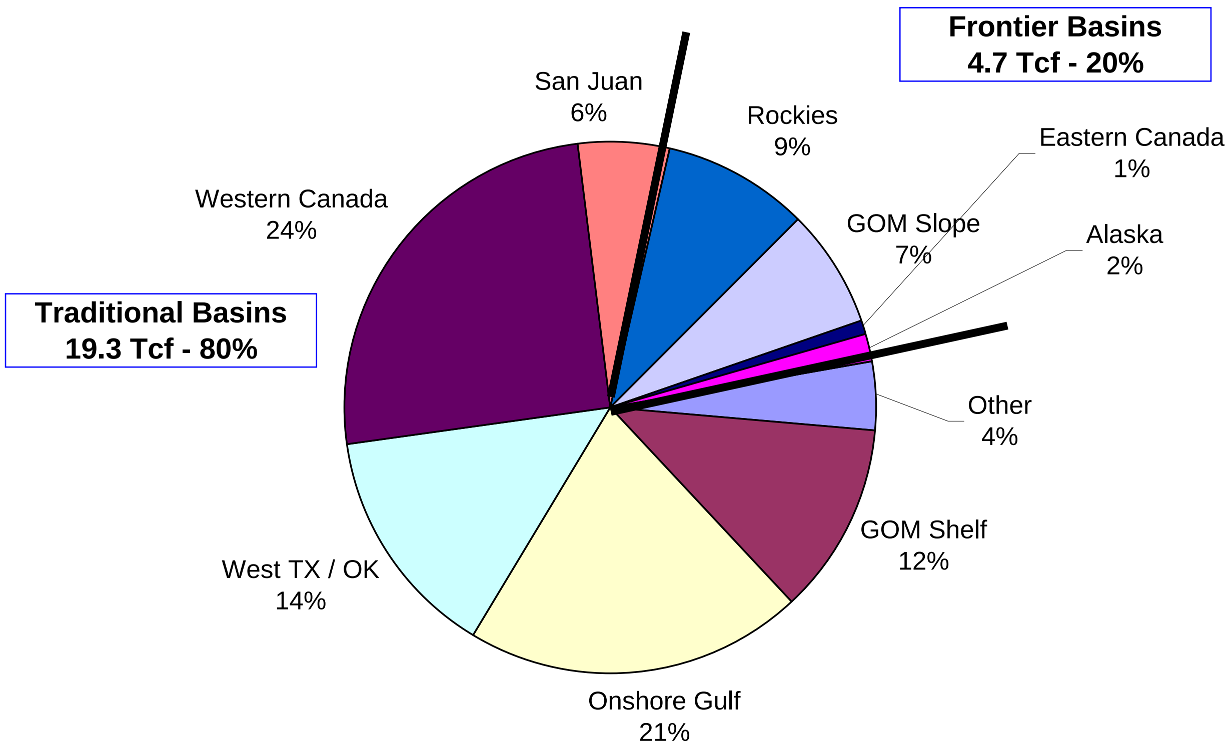
[13] "Fracturing down hole" is the process of breaking the rock in the producing region of the well in order to increase the rate of production.

Figure 4-2
North American Natural Gas Production by Region



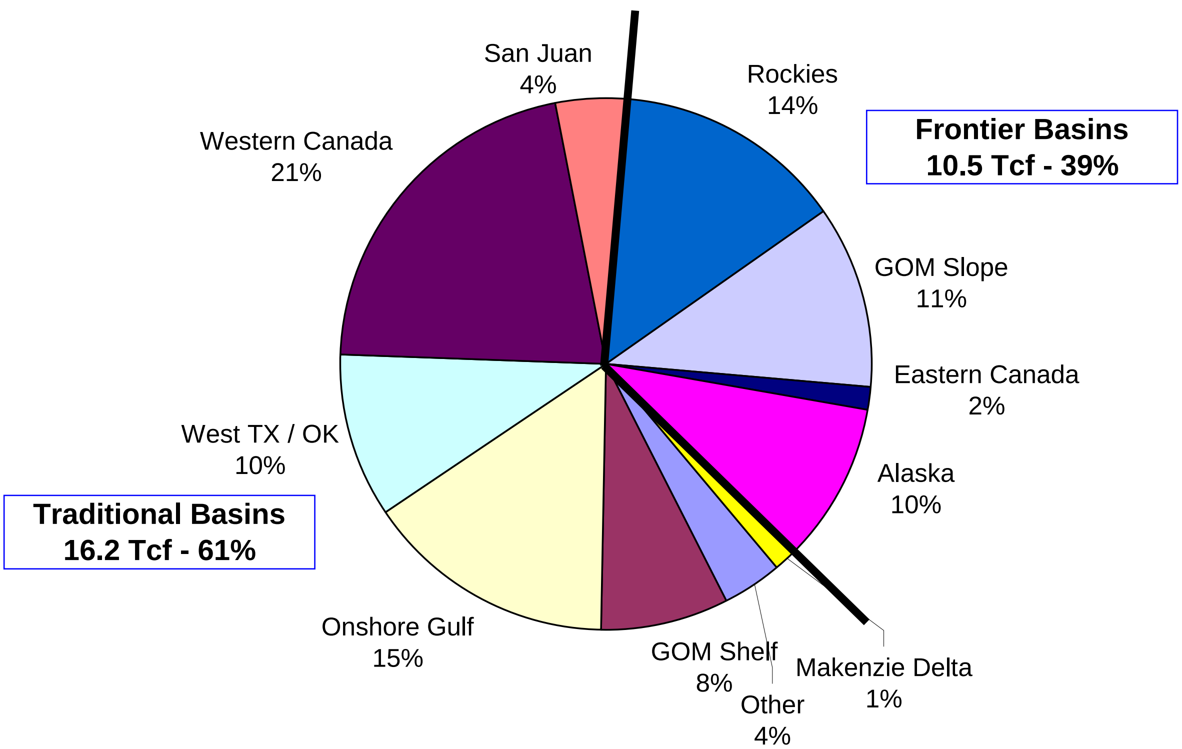
North American production including gas produced and consumed in Canada but excludes Mexico

Figure 4-3
2003 North American
Natural Gas Production by Region



Hence, much of the growth of the gas market over the next 20 years must be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets in North America. LNG imports must also play a key role (see next section). Frontier basins in the arctic, such as Alaska and the Mackenzie Delta, new offshore regions, such as the Gulf of Mexico Slope and Offshore Eastern Canada, and underdeveloped domestic areas such as the Northern Rockies all will be needed to serve U.S. Demand by 2020. Of course, to bring gas from the new supply regions, pipeline infrastructure will have to be built.

Figure 4-4
2020 North American
Natural Gas Production by Region



Current supplies from "frontier" basins are 4.7 Tcf per year and account for 20% of North American natural gas production (Figure 4-3). By 2020 the volumes could more than double to 10.5 Tcf per year and account for nearly 40% of North American production. (Figure 4-4). The EEA Base Case specifically includes:

- 3.1 Tcf per year of gas production from the deeper waters[14] in the Gulf of Mexico. Deepwater gas production will grow to 11 percent of North American gas production by 2020.
- 3.9 Tcf per year of gas production from the Rocky Mountains (excluding the San Juan Basin). Rocky Mountain gas production will grow to over 14 percent of North American gas production by 2020. Much of the increase in production is driven by

14 Production from water depths exceeding 200 meters.

development of unconventional sources such as coal bed methane.

- 2.7 Tcf per year of Alaska gas production, 2.2 Tcf of which flows south to Canada and the Lower-48. Alaska gas production will account for 10 percent of North American gas supply by 2020.
- 0.4 Tcf per year of MacKenzie Delta gas production, most of which may remain in Western Canada for oil shales development.
- 0.5 Tcf per year of Eastern Canada offshore gas production, most of which will satisfy growth in gas demand in the Northeast U.S. Eastern Canada offshore production will grow to almost 2 percent of North American gas supply by 2020.

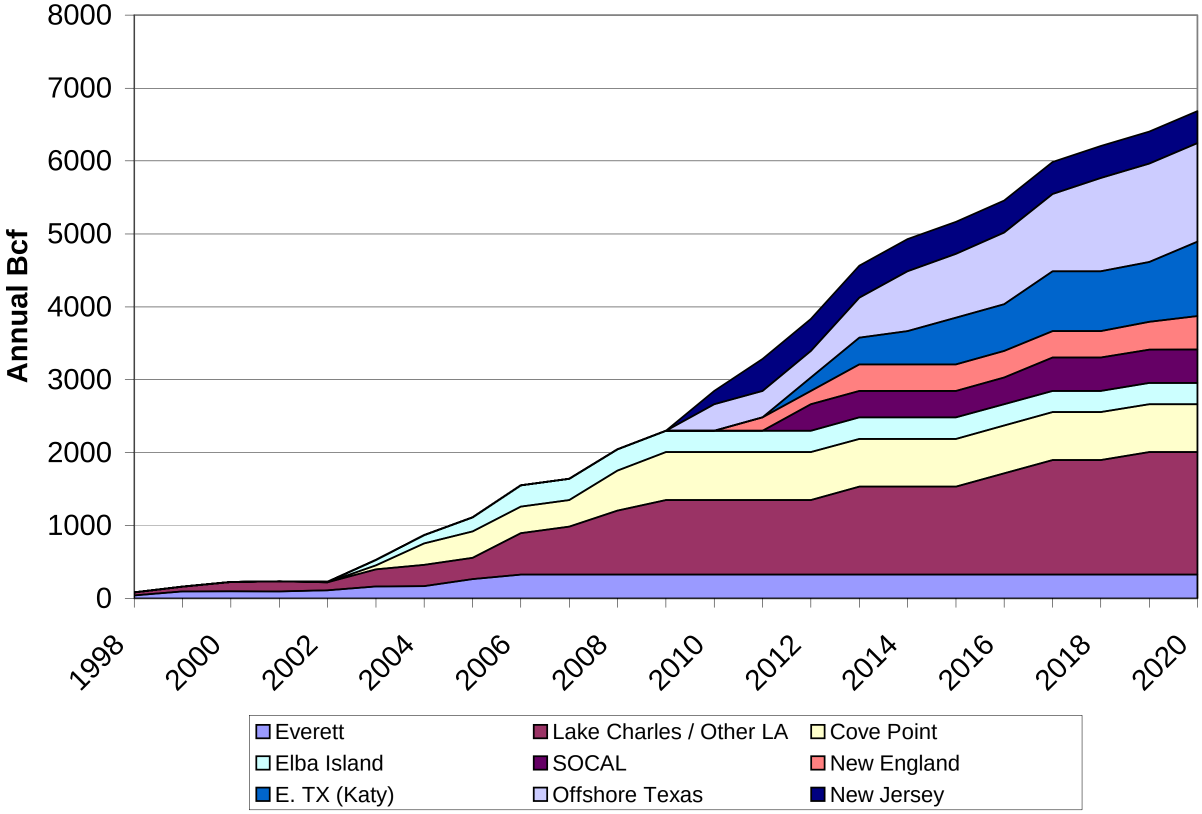
Although actual amounts and timing of production from frontier basins will vary from the EEA Base case, supplies from such regions will be significant by the end of the next decade.

LNG Imports

In addition to the need for gas production from more remote locations, the base projection relies on an order-of-magnitude increase in LNG imports to meet the requirements of the U.S. market. U.S. LNG imports for 2002 totaled 229 Bcf. Imports for 2003 doubled the previous year at 475 Bcf. By 2020, U.S. LNG imports could be over 6,600 Bcf per year, nearly a thirty-fold increase from 2002. Figure 4-5 presents the forecast of the amount and location of imports and exports of LNG assumed in the study. Currently, there are four operating LNG import terminals in North American.[15] In order to attain the level of LNG imports assumed in the EEA Base Case, approximately 10 additional terminals will need to be constructed.

[15] In addition to the four import terminals, there are more than 100 LNG peak shaving facilities that are used principally by local distribution companies to meet peak day demand.

Figure 4-5
U.S. LNG Imports (Bcf / Year)



LNG deliveries compete with wellhead production. LNG is competitive with North American production at prices ranging from $3.50 to $4.00 per Mcf depending upon the distance that the LNG travels from the liquefaction plant to the import terminal. Imported LNG, in large part, becomes an economically viable energy supply because of the low cost of developing and producing abundant stranded gas resource located throughout the world. Most of the gas may be developed and produced at costs under $1 per MMBtu at the wellhead, but the variable costs of liquefaction, tankering, and regasification are significant. Hence, the delivered cost of LNG imports are high, making LNG one of the most expensive sources of new supply on a unit basis. Unlike domestic or Canadian supplies, the U.S. must compete with the rest of the world for LNG. World market conditions influence LNG prices.

In addition to expansion plans at the existing four import terminals, there are nearly 40 new LNG terminals proposed for North America. Obviously not all of them will be built. Actual locations for new terminals will not only be based on economic factors such as proximity to consuming markets but also political factors of permitting and siting. There is significant value in siting LNG terminal facilities in "market area" locations that are downstream of pipeline constraints such as the Northeast U.S. However such locations may have limited pipeline access or face additional hurdles in permitting. Terminals along the Gulf of Mexico will have access to a more extensive pipeline network but may receive a lower price for their natural gas supplies. In the end, a mix of supply area and market area terminals will most likely be built. Of the four existing terminals, 3 are on the East Coast, Everett, Cove Point, and Elba Island; While Lake Charles is located along the Gulf of Mexico. The EEA Base case assumes 2 additional East Coast terminals, 7 Gulf Coast terminals and 1 terminal on the West Coast.

Imports and Exports from Mexico

Exports to Mexico have increased from a little over 100 Bcf in 1998 to over 1 Tcf in 2003 (Table 4-2). Growth in gas demand in Mexico, driven substantially by increased gas requirements for power generation, has exceeded growth in supply. Consequently, Mexico has needed to import increasing quantities of gas from the United States over the past five years.

Mexico has a significant gas resource base of its own. However, much of the resource base is in Southern Mexico and would require the development of pipeline infrastructure to bring the gas to the market regions just south of the U.S. border. A considerable amount of gas is contained in the Burgos region across the Texas border. The forecast used in this analysis assumes that development of the indigenous gas resource in North Mexico is used to stabilize the level of required imports from the North by the end of the decade.

In addition, the projection anticipates the construction of two LNG terminals, one on the East Coast in Altimira, and one on the West Coast in Baja California. Both would supplement Mexico's domestic production reducing the need for imports by 585 Bcf per year after 2006. Excess imports of LNG on the West Coast provides for net exports to the U.S. on the order of 185 Bcf per year.

Table 4-2
Net Mexican Imports/ (Exports)[16]
(Bcf per Year)

Year	Reynosa	Juarez	Naco	Baha	Total
1998	13	(104)	(12)	0	(102)
1999	136	(136)	(11)	0	(11)
2000	(53)	(148)	(25)	(34)	(259)
2001	(85)	(171)	(33)	(77)	(366)
2002	(305)	(271)	(44)	(125)	(745)
2003	(511)	(264)	(84)	(198)	(1,057)
2004	(606)	(281)	(128)	(276)	(1,291)
2005	(745)	(330)	(169)	(350)	(1,594)
2006	(126)	(338)	(174)	(67)	(705)
2007	10	(338)	(175)	71	(432)
2008	(109)	(338)	(176)	209	(414)
2009	(224)	(337)	(177)	197	(542)
2010	(332)	(337)	(178)	185	(662)
2011	(343)	(337)	(178)	184	(674)
2012	(345)	(337)	(178)	184	(676)
2013	(342)	(337)	(178)	184	(673)
2014	(342)	(337)	(178)	184	(672)
2015	(341)	(337)	(178)	184	(672)
2016	(344)	(337)	(178)	184	(674)
2017	(341)	(337)	(178)	185	(671)
2018	(340)	(337)	(178)	185	(670)
2019	(340)	(337)	(178)	185	(670)
2020	(342)	(337)	(178)	185	(672)

[16] Exports to Mexico are negative, a reduction in supply to the U.S. Imports from Mexico are positive, a source of supply to the U.S.

5
NATURAL GAS MARKET DYNAMICS

Like most studies of natural gas markets, the previous two sections of this report consider natural gas demand and supply separately.

Natural gas is a commodity that is produced and consumed at many different locations throughout North America[17]. It is also physically and financially traded at many different locations, often referred to as market centers. Table 5-1 provides a list of the major locations at which gas is commonly traded.

Most economists would agree that the North American natural gas market is a deregulated, competitive, and fairly integrated and liquid market where gas prices represent market-clearing prices between supply and demand. Further, because the market is fairly integrated, price basis[18] differentials between regions represent the opportunity cost to move gas between the market centers.

Figure 5-1 illustrates the fundamental economic relationships among supply, price, and demand that act to equilibrate natural gas markets. In all sections of the market, price response differs depending on the situation in the market. Production and storage become very price inelastic as they approach the limits on deliverability. Pipeline transmission value also becomes very price inelastic as capacity limits are reached.

[17] Throughout this report, unless otherwise noted, North America statistics include the U.S. and Canada, but exclude Mexico. However, the analysis considers gas trade between the U.S. and Mexico.

[18] Term refers to regional natural gas price differentials reflecting the difference between the price of gas at two locations.

Once capacity is reached, available supply changes very little, regardless of price. As a result, once capacity is reached, the market equilibrates primarily based on demand

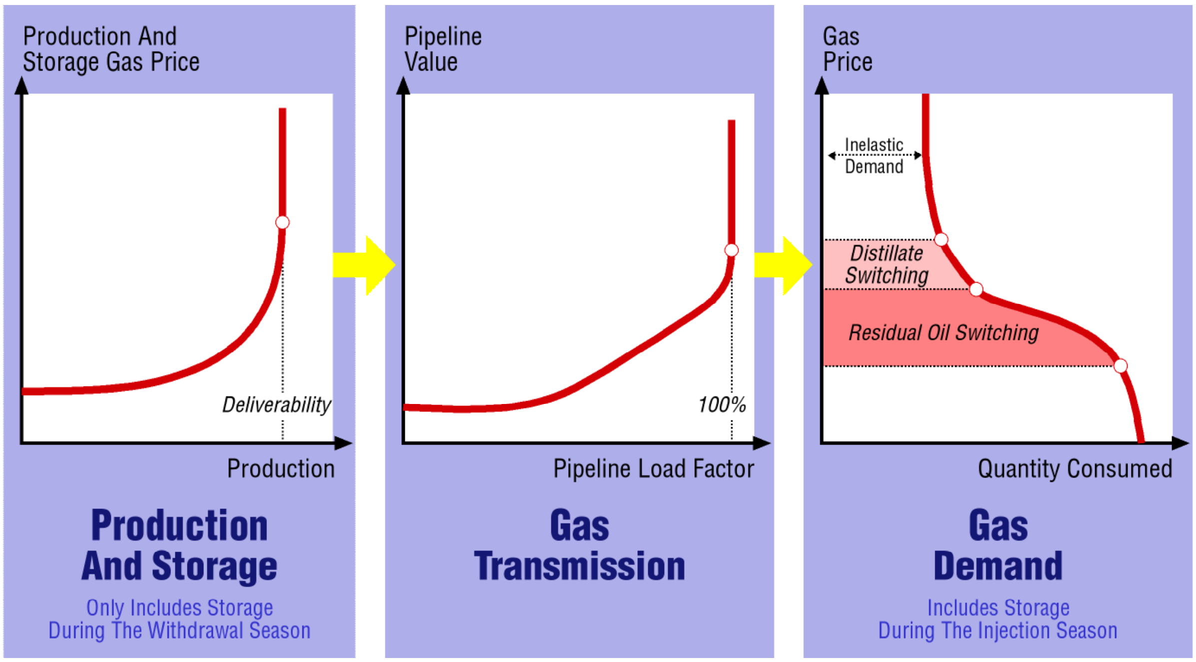
Table 5-1
Major North American Pricing Locations

Source: Platts Gas Daily

Region/Area	Gas Daily Location	Region/Area	Gas Daily Location
New England	Citygates - Algonquin, citygates	Eastern Louisiana Hub	Louisiana - Tennessee, LA, 500 leg
Quebec	Canadian Gas - Iroquois receipts	Eastern Louisiana Hub	Louisiana - Trunkline ELA
New York City	Citygates - Iroquois, Zone 2	Eastern Louisiana Hub	Louisiana - Transco, Zone 3 (St. 65)
New York City	Citygates - Transco, Zone 6 (NY)	Eastern Louisiana Hub	Louisiana - Southern Natural, LA
Eastern New York	Citygates - Tennessee Zone 6 delivered	Eastern Louisiana Hub	Louisiana - Texas East, ELA
Eastern New York	Other - Algonquin receipts	Eastern Louisiana Hub	Louisiana - Florida Gas, Zone 3
New Jersey	Citygates - Transco Z6 non-NY	East Louisiana Shelf	Louisiana - Columbia Gulf, LA
New Jersey	Citygates - Texas Eastern, M-3	Henry Hub	Louisiana - Tennessee, La. 800 leg
Niagara	Canadian Gas - Niagara	Henry Hub	Louisiana - ANR, LA
Niagara	Citygates - Tennessee, Zone 5 delivered	Henry Hub	Louisiana - Trunkline, WLA
Leidy	Appalachia - Leidy Hub	Henry Hub	Louisiana - NGPL LA
Leidy	Appalachia - Dominion, North Point	Henry Hub	Louisiana - Henry Hub
South Florida	Citygates - Florida city-gates	Henry Hub	Louisiana - Gulf, S.La/East Side
East Ohio	Appalachia - Dominion South Point	Henry Hub	Louisiana - Texas Gas, Zone SL
East Ohio	Appalachia - Columbia Gas, Appalachia	Henry Hub	Louisiana - Texas Eastern WLA
North Illinois	Citygates - Chicago city-gates	Henry Hub	Louisiana - Transco, Zone 2 (St. 45)
Southeast Michigan	Citygates - Mich Con City-gate	Henry Hub	Louisiana - Florida Gas, Zone 2
Southeast Michigan	Citygates - Consumers Energy city-gate	North Louisiana Hub	Louisiana - Columbia Gulf, Mainline
Wisconsin	Other - ANR ML7	North Louisiana Hub	East Texas - MRT, Mainline
Ventura	Other - NGPL Iowa-Ill. Receipt	Southwest Texas	Permian Basin - El Paso, Permian Basin
Ventura	Other - Northern, Ventura	Southwest Texas	Permian Basin - Waha
Emerson Imports	Canadian Gas - Emerson, Viking GL	Southwest Texas	Permian Basin - Northern, MIDS 1-6
Nebraska	Other - Northern, demarc	Southwest Texas	Permian Basin - Transwestern, Permian Basin
OK/KS	Oklahoma - ANR, Okla	NE TX (Carthage)	Oklahoma - Reliant, East
OK/KS	Oklahoma - Reliant, West	NE TX (Carthage)	East Texas - Carthage Hub
OK/KS	Oklahoma - NGPL, Midcontinent	NE TX (Carthage)	East Texas - Texas Eastern, ETX
OK/KS	Oklahoma - Panhandle, Tx.-Okla.	NE TX (Carthage)	East Texas - Texas Gas, zone 1
OK/KS	Other - Northern Tx-Okla.-Kan.	NE TX (Carthage)	East Texas - Lone Star
Opal	Rockies - CIG Rocky Mountains	NE TX (Carthage)	East Texas - NGPL TexOk Zone
Opal	Rockies - Kern River, Opal plant	NE TX (Carthage)	East Texas - MRT West leg
Opal	Rockies - Northwest, Wyo. Pool	E. TX (Katy)	Texas East - Katy Hub
Opal	Rockies. - South of Green River	E. TX (Katy)	Texas East - Florida Gas, Zone 1
Opal	Rockies. - Questar Rocky Mountains	E. TX (Katy)	Texas East - Houston Ship Channel
Cheyenne	Rockies - Cheyenne Hub	E. TX (Katy)	Texas East - Transco
EPNG/TW	New Mexico SJB - El Paso, Bondad	E. TX (Katy)	Texas East - Tennessee
EPNG/TW	New Mexico SJB - El Paso, San Juan Basin	E. TX (Katy)	Texas East - Texas East
SOCAL Area	Other - SoCal Gas	E. TX (Katy)	Louisiana - Florida Gas Zone 1
Enhanced Oil Recovery Region	Other - PG&E, South	S. TX	Texas South - Agua Dulce hub
Malin Interchange	Other - PG&E, Malin	S. TX	Texas South - Houston Pipe Line
PGE Area	Citygates - PG&E citygate	S. TX	Texas South - Trunkline, Texas
North British Columbia	Canadian Gas - Westcoast, Station 2 (US$/MMBtu)	S. TX	Texas South - NGPL G1
Caroline	Canadian Gas - NOVA, AECO (US$/MMBtu)	S. TX	Texas South - Transco, Zone 1
Dawn	Canadian Gas - Dawn, Ontario	S. TX	Texas South - Tennessee, Zone 0
Kingsgate Imports	Canadian Gas - PGT-GTNW, Kingsgate	S. TX	Texas South - EPGT, Texas
Huntingdon Imports	Canadian Gas - Northwest, Can. Bdr. (Sumas)	S. TX	Texas South - Texas East, STX
NPC/PGT Hub	Rocky Mtns. - Stanfield, Ore.	OK/KS	Oklahoma - Williams. Tx.-Okla.-Kan.
Alabama Offshore	MS/AL - FGT Mobile Bay	OK/KS	Oklahoma - Oneok, Okla.
Mississippi/South Alabama	MS/AL - TransCo, Zone 4 (St. 85)	NW TX	Others - NGPL, Amarillo receipt
Mississippi/South Alabama	MS/AL - Texas Eastern M-1 (Kosi)	West Virginia	Appalachia - Columbia Gas, Appalachia

price response. Demand price response differs depending on natural gas price levels relative to other fuels. Natural gas demand is much more price elastic when gas prices are competitive with residual fuel oil and/or distillate fuel oil. When gas prices exceed the point at which available dual-fired capacity has switched from natural gas to oil,

Figure 5-1
Gas Price Fundamentals: Gas Quantity and Price Equilibrium



price elasticity drops, and it takes a significant increase in price to produce a small reduction in demand. When gas prices are below the point at which most dual-fired capacity has switched from oil to natural gas, a large decrease in price would be necessary to stimulate additional demand.

The extensive natural gas pipeline in North America connects regional gas markets and allows supplies to move to the market that places the greatest marginal value on incremental supplies[19]. However, as the pipeline load factor increases, the value of the pipeline capacity – reflected in the basis differentials between regional markets – also increases. Pipeline transmission value becomes very price inelastic as capacity limits are reached. Once capacity is reached, available supply changes very little, regardless

19 According to the U.S. Department of Transportation, Office of Pipeline Safety, the U.S. Energy Information Administration, and Statistics Canada, there are over 260,000 miles of interstate and interprovincial gas pipeline throughout North America. There is sufficient capacity connecting different regional gas markets to create a high price correlation between different regional markets throughout most of the year.

of price. Once capacity is reached, the market equilibrates primarily based on demand response.

As a result, when pipeline capacity is available, regional markets are connected and the gas prices in those markets are closely correlated. The supply/demand balance in the connected market reflects the economic options of a broad number of buyers and sellers as well as transportation value (basis) between the markets. When pipeline load factors increase to approach the constraints (generally between 80 and 90 percent utilization on a monthly basis), regional markets can disconnect from the broader North American market.

Producer Response to Price Changes

In the natural gas market, producers have limited ability to respond quickly to changing price conditions. Under all but the lowest price conditions, producers market a very high percentage of their total wellhead gas deliverability. Deliverability increases require new drilling activity, which takes three to nine months to affect available supplies significantly. As a result, near-term wellhead production is generally quite inelastic. When prices increase, significant increases in production occur only after the substantial lead-time associated with new resource development. When prices decrease, production can be shut-in. However, well shut-ins tend to occur only at very low prices. Natural gas and oil production are very up-front capital intensive, with relatively low marginal costs of producing gas from an existing well. Even at low prices, most wells remain economic to operate, as marginal revenues will exceed marginal lifting costs for all but the least economic wells. The positive cash flow provides a strong incentive to continue to produce even when prices are much lower than expected.

In the longer term, an increase in expected prices provides the incentive needed to elicit investment in new supply. Natural gas and oil resources have a planning horizon of one to three years for resources in existing onshore and shallow offshore fields, and up to a ten-year horizon for frontier resources such as Arctic gas. In addition, investment cash flow is determined by the life of the producing asset, which can be from three to twenty years. Price expectations over this extended time frame will determine investment in new production.

Natural Gas Storage Response to Price Change

Natural gas can be stored economically. As a result, storage injection and withdrawal behavior act to moderate gas price volatility to a certain extent. However, a number of factors other than economic price arbitrage impact injection and withdrawal behavior. Most LDCs in cold weather climates rely on storage to meet winter season and peakday loads. The LDC gas supply plan relies on target levels of storage at different points in the season. Moreover, tariff penalties and price ratchets based on storage inventory levels can limit the flexibility needed to optimize storage economically by creating a price penalty for storage activity outside of set parameters. Nevertheless, implementation of storage management programs and the development of high-deliverability storage provide a significant physical hedge – and actually serve to mitigate daily and seasonal price volatility.

Infrastructure Response to Price Changes

Energy infrastructure constraints, particularly of natural gas pipeline capacity, and electricity generation and transmission capacity constraints, appear to be one of the key causes of recent price volatility. In the last several years, both California and New York City have experienced periods during which both electricity and natural gas demand have exceeded the available power generation capacity and natural gas pipeline capacity. When use of these physical assets approaches capacity, prices tend to increase, sometimes increasing very rapidly in reflection of scarcity rents associated with the assets. Infrastructure constraints can lead to both short-term price volatility, when demand exceeds capacity due to short-term factors such as weather, and long-term price volatility, when capacity fails to increase with demand growth or (in the case of some natural gas pipelines) natural gas production capacity.

The ability of existing holders of capacity to sell gas transportation capacity in a manner that captures the full market value of the capacity is a critical incentive to encourage additional investment in new capacity. In times of pipeline capacity constraint, the value of the capacity can greatly exceed the regulated rate paid for the capacity. [20] The existing capacity holder can capture the value of this price differential even though there is a "cap" imposed on the re-sale of capacity by selling the gas itself at the delivery point. Competition among a number of shippers to participate in the market helps to prevent monopoly behavior. Even though additional pipeline capacity will erode the transportation value by relieving the constraint, the desire of shippers to obtain a "first mover's" advantage between constrained markets can overcome to some degree the reluctance to contract for new capacity.

In contrast, the pipeline operator's cannot capture the full value and economic rent because the pipeline is prohibited from selling capacity for more than the maximum regulated rate. As a result, the economic incentive to build pipelines must be generated indirectly through the actions of the shippers.

Allowing market participants an opportunity to capture the full value and scarcity rents for some period is particularly important in a deregulated market. In the current regulated market, return on investments in natural gas pipelines and power generation capacity is no longer guaranteed via regulated rates of return. As a result, some party must have up-side opportunity so that there is incentive to reduce the risk to the regulated pipeline by signing longer-term contracts.

[20] In economics, this value in excess of cost of production is termed "an economic rent."

Consumer Response to Price Changes

Consumers' responses to price changes vary by type of customer and application. In the short-term, traditional residential and commercial gas customers show very little price elasticity. These customers adjust their demand principally in response to external factors such as weather and economic activity[21]. Thus, they provide little in the way of short-term demand response, and changes in gas prices to these customers' results principally in a transfer.[22]

Large industrial and power generation customers with dual-fuel capability[23] can and do respond to price changes by switching fuel sources based upon the relationship between the gas price and the alternative fuel price (generally distillate or residual fuel oil).[24] However, the overall price elasticity of gas demand declines significantly once all of the easily switched customers are "off gas".

Other than fuel switching, the industrial sector's response to increasing gas prices is to cut consumption by reducing output and to implement process changes to improve energy efficiency. However, because of the general economic imperative to improve profits, most energy-intensive industries have already taken the "easy" actions to reduce energy consumption. Most significant changes take weeks, months, or years to accomplish and may involve replacing equipment. Moreover, once taken, these actions often represent a demand shift because the demand reductions achieved are not usually offset by increases when gas prices fall again. For example, customers will not

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21 Under very high gas price conditions, there is a limited response due to thermostat turn-back or other conservation measures. However, these changes are slow in coming because consumers don't immediately see the higher prices due to billing cycles and the lag in utility rates.

22 The same can be said for the response in electricity demand to changes in electricity prices. The only recent instance indicating significant demand response occurred in California, where residential and commercial sector demand was reduced by an estimated 5 to 7 percent. However, the demand reduction was a combination of the price response and "good-citizen" behavior in response to governmental calls for action. Economic literature has yet to identify definitively the magnitude of the price response.

23 The dual-fuel segment of the gas market represents approximately 8 to 10 percent of the U.S. gas market.

remove new, more efficient equipment in response to lower prices, and industrial production capacity moved to other countries in order to find lower fuel costs is unlikely to return.

As a result, the industrial sector behavioral response to short-term imbalances in the gas supply/demand balance – beyond fuel switching – is limited to changes in industrial output. Even for such gas-intensive industries as ammonia, methanol, aluminum and steel production and processing, significant demand response occurs only when prices rise to the point that the product becomes un-competitive in the world market. For most manufacturing industries, where gas costs represent less than five percent of the gross value added of the industrial process, very large gas price increases are needed to change output significantly.

The power generation segment of the market also can and does respond to gas price changes, in this case by shifting the dispatch of generating units. When gas prices fall, gas-fired generation can displace oil or coal units. When gas prices rise, gas-fired generation can be reduced if there is additional non-gas fired capacity that is not being utilized. Unfortunately, under most market conditions, the gas capacity provides generation at the margin. It is dispatched only after virtually all other sources of capacity are utilized. As a result, power generation gas demand does not provide a significant demand response in a "tight" gas market with rising prices. Indeed, in California, when power prices exploded to record heights[25], power generation customers were willing to pay astronomically high gas prices, since electricity prices made it economically feasible to do so.

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[24] Such fuel switching occurs so long as the alternative fuel is available and the facility has the necessary air emission permits.

[25] According to *Platt's Gas Daily,* the SOCAL daily index was as high as $59 per MMBtu (12/12/00). Individual trades were as high as $72 per MMBtu.

Gas Price Volatility and Natural Gas Infrastructure

The recent volatility in gas prices – particularly the experience of the 2000-01 winter and January and February of 2003– occurred because of the tightness in gas production and the fact that the supply/demand imbalances became too large to be moderated by the behavior of customers who could easily respond to changing price conditions. As a result, large and rapid price movements occurred.

Figure 5-2
Supply and Demand Curves under Different Price Environments

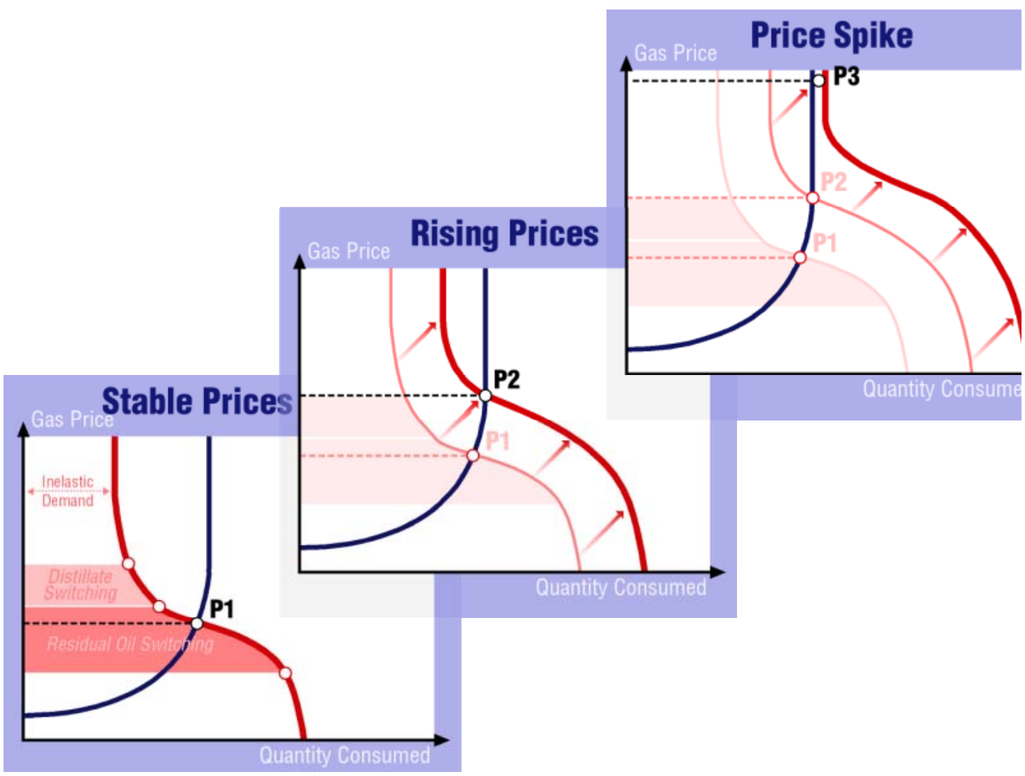


Figure 5-2 illustrates the impact of a tightening of natural gas markets on the volatility of price response to shifts in demand. As illustrated at point P1 of the "Stable Prices" box in this figure, when natural gas prices are competitive with residual fuel oil, the price elasticity of demand tends to be relatively high. At this point, sufficient energy demand switches between natural gas and fuel oil to ensure relatively stable prices. When the natural gas markets are tighter, and a significant share of the dual fuel demand has shifted to the alternate fuel, an increase in demand will lead to relatively larger increases in prices. This is reflected at point P2 in the figure. However, in the very tight markets shown at point P3, when most of the fuel switchable capacity has switched away from natural gas, an increase in demand due to weather conditions or other factors will lead to natural gas price spikes such as those observed recently in California, New York City, and nationally during the 2000/2001 winter and February of 2004.

The challenge for the policy makers and the industry alike is to develop framework that promotes the construction of natural gas infrastructure that is economically justified while preserving the consumer efficiency benefits provided by market forces.

Impact of Delays in the Construction of Natural Gas Infrastructure

A new pipeline or capacity expansion project is economically justified when the basis differential – the difference between the gas price at the delivery point for the anticipated project and gas price at the receipt point – is expected to be equal to or greater than the cost of the pipeline project. In other words, if the difference between the gas price in market region B and the gas price in production region A is greater than the cost of per MMBtu of transporting gas along a new pipeline going from A to B, economic efficiency demands that the pipeline should be built.

When a pipeline project is delayed beyond the point where it is economically justified, the result is to create transportation constraints that persist until the construction is completed or other elements of the market adjust to bring the market back into balance. As described above, the constraint increases the value of the scarce pipeline capacity in the marketplace, affecting the markets at both ends of the prospective infrastructure project.

When pipeline capacity is constrained the result is to send “price signals in both directions – upstream and downstream. Prices downstream of the pipeline constraint in the market area are increased as the “invisible hand” of the market attempts to reduce demand to the point where the supply of gas is adequate.

However, upstream of the constraint in pipeline capacity, the impact is to place downward pressure on gas prices. The effect of this downward pressure in production areas is to send a “price signal” to producers to ***reduce*** drilling activity. Future production of natural gas upstream of a pipeline constraint is lower than production otherwise could be, regardless of the need for incremental gas supplies in consuming regions.

Natural gas deliverability upstream of the pipeline capacity constraint responds much more quickly to periods of depressed prices now than it did in the 1980s and early 1990s. During that period, a “bubble” for natural gas persisted for years. However, a number of factors including improvements in E&P technology that increase decline rates and changes in the capital budgeting practices of producers, prevent a recurrence of a bubble even in a “bottlenecked” supply region. As a result, the supply capacity is simply lost to consumers.

From 2000 through 2003, U.S. lower-48 gas production averaged about 18.7 Tcf per year or 51.2 Bcfd (Table 5-2). With the exception of 2000 to 2001 when production increased, the trend has generally been towards declining production as the U.S. gas resource continues to mature. Every producing area has declined, except the Rocky Mountains where the two largest producing areas, the Powder River Basin and the Green River Basin have experienced significant growth over the past few years. After a fairly robust decline in production between 2001 and 2002, the Gulf Coast Offshore showed signs of stabilizing in 2003, with continued growth in production from the deeper waters offsetting declining production in the shallow waters.

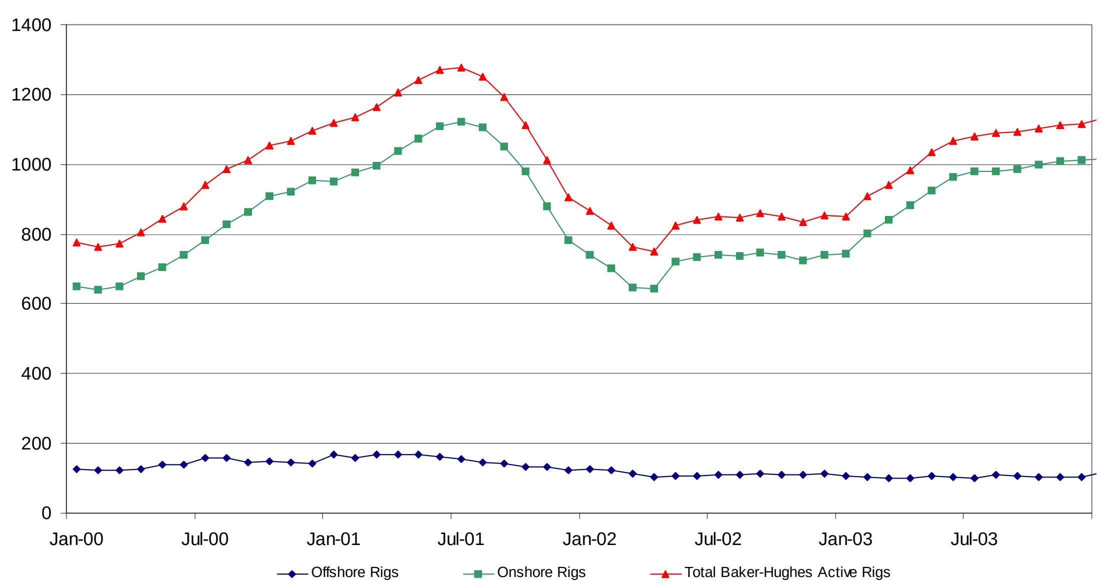
Table 5-2
Recent Trends in U.S. Lower-48 Gas Production (Bcf)

					Annual Change - BCF		
Region	**2000**	**2001**	**2002**	**2003**	**2001**	**2002**	**2003**
West Coast Onshore	286	291	289	294	5	-2	5
Great Basin	90	95	100	92	5	5	-8
Rockies	3,097	3,260	3,376	3,486	163	116	110
West Texas	1,756	1,761	1,712	1,695	5	-49	-17
Gulf Coast Onshore	5,070	5,085	4,945	4,897	15	-140	-48
Mid-continent	2,317	2,287	2,238	2,223	-30	-49	-15
Eastern Interior	938	936	890	887	-2	-46	-3
Gulf of Mexico	5,196	5,233	4,928	4,882	37	-305	-46
U.S. Pacific Offshore	48	47	47	47	-1	0	0
Lower 48 Total	**18,798**	**18,995**	**18,526**	**18,504**	**197**	**-469**	**-22**

Source: EEA Base Case January 2004

The production increase between 2000 and 2001 was a result of the increased drilling activity during those years (Figure 5-3). In response to high oil and gas prices, the U.S. rig count increased from about 800 active rigs in early 2000 to a peak of over 1,200 active rigs in the second quarter of 2002, the highest level in recent history.

Figure 5-3
Recent U.S. Drilling Activity



Source: Baker Hughes Rig Count

Because of the extremely warm weather in the winter if 2002-03, gas prices moderated substantially. Oil prices also eased sending the price signal to producers to reduce activity from the record levels. Rig activity fell back to a more modest level of about 800 active rigs by mid-2002. This decline is the primary reason for declining production in 2002-03. Natural gas prices increased again in 2003, and rig activity increased as well. By the end of 2003, the active rig count had risen back up to just over 1,100 rigs, and gas production has showed signs of stabilizing. It appears that the current level of activity of 1,100 to 1,200 rigs is necessary to keep production constant. In the future, we would expect that rig activity will have to rise to higher levels to keep production constant as the best gas resource continues to be developed and depleted.

Gas well completions in the U.S. lower-48 have risen and fallen with rig activity, although there appears to be a six-month lag between rig activity and completions (Table 5-3). The recent peak in well completions occurred in 2001 with over 21,000 gas well completions. There have been almost 17,000 to 18,000 gas wells completed in each of the other years, when drilling activity was at much lower levels. About one-third of recent gas well completions are in the Rocky Mountains even though the area accounts for only 20 percent of the U.S. production. The wells in the area, particularly the Powder River Basin coalbed methane wells tend to have lower productive capacity than the average U.S. well. In each of the past few years, there have been between 2,000 to 3,000 wells drilled in the Powder River Basin. On average, wells in the Eastern Interior part of the U.S. are also less productive than the average U.S. gas well. Hence, the Eastern Interior accounts for 15 percent of the gas well completions but only 5 percent of U.S. production.

Table 5-3
Recent Trends in U.S. Gas Well Completions

					Annual Change		
Region	**2000**	**2001**	**2002**	**2003**	**2001**	**2002**	**2003**
West Coast Onshore	71	100	84	145	29	-16	61
Great Basin	14	15	17	19	1	2	2
Rockies	5,680	7,277	6,944	5,804	1,597	-333	-1,140
West Texas	1,369	1,867	1,523	1,686	499	-344	163
Gulf Coast Onshore	3,727	4,608	3,969	4,345	881	-639	375
Mid-continent	2,244	2,985	2,369	2,524	742	-617	155
Eastern Interior	2,521	3,392	2,563	2,670	871	-829	107
Gulf of Mexico	975	1,030	751	790	55	-279	40
U.S. Pacific Offshore	0	0	0	0	0	0	0
Lower 48 Total	**16,600**	**21,274**	**18,220**	**17,983**	**4,674**	**-3,054**	**-237**

Source: EEA Supply Service Database - February 2004

The rapidity of the response in gas production to moderating prices is now a permanent feature of natural gas production economics. Given the need to drill large numbers of wells simply to maintain production, even temporary declines in drilling activity can have substantial impacts on gas markets and gas consumers. The magnitudes of these impacts that arise from delays in the construction of natural gas infrastructure are quantified in section 7 of this report.

6
TRANSMISSION AND STORAGE INFRASTRUCTURE

With few exceptions[26], the EEA Base Case is constructed assuming that pipeline and storage infrastructure that is economically justified is built within a year or so of when the basis differentials justify the construction. The following presents a discussion of transmission and storage infrastructure that is economically justified and needed to deliver natural gas into consuming markets.

If the U.S. market is to satisfy demand fundamentals in an efficient manner by the end of the next decade, significant pipeline and storage infrastructure investment, on the order of $61 billion (in constant 2003 dollars), must be made in both the U.S. and Canada (Figure 6-1). Approximately $19 billion of investment will be needed for replacement of current pipe simply to maintain existing pipeline capacity. Recently enacted pipeline integrity inspection requirements will require that additional investment in equipment such as “pig launchers and catchers”[27] will need to added to the existing pipeline network. In addition, a considerable amount of pipe will be needed in market areas, to attach new power plants and industrial customers and in supply regions to access supply. Storage must be added to serve larger markets. As discussed in section 4, gas pipeline capacity must be built to bring gas to markets from new regions of North America. Nearly $42 billion will be needed for new pipeline and storage projects. Of that $18 billion will be associated with the Alaskan and MacKenzie Delta projects to bring arctic supplies of gas to market.

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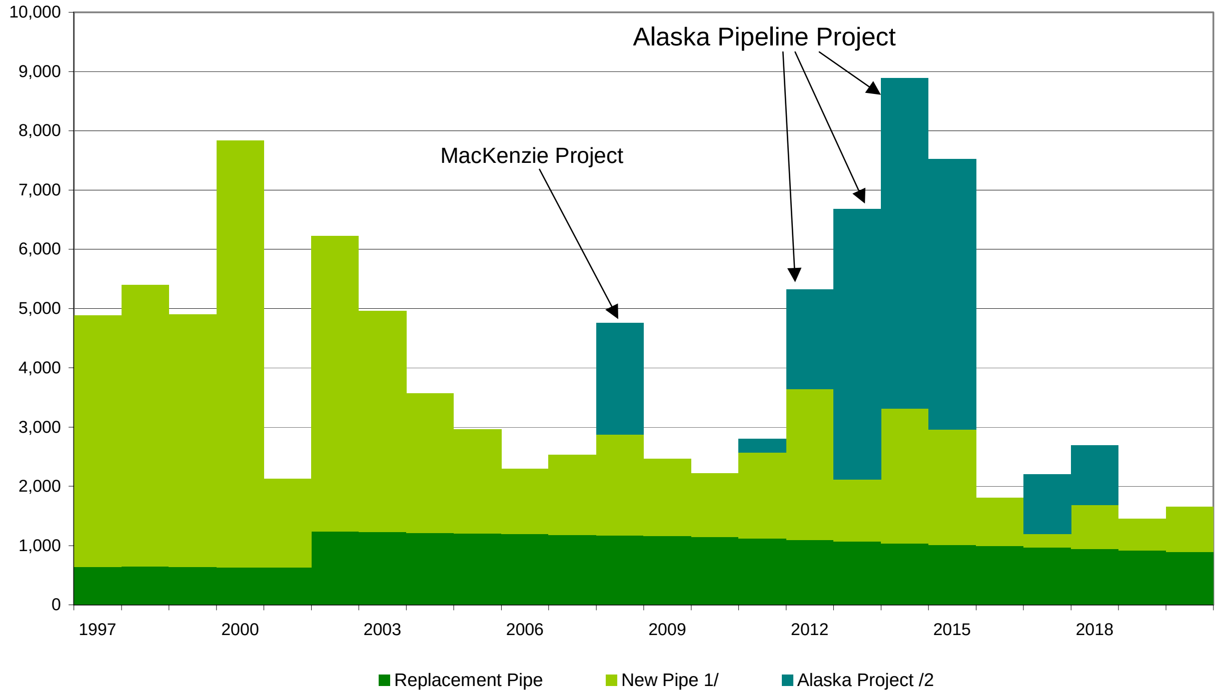
[26] In some markets, such as New York City, additional pipeline capacity is already economically justified by the “economic” criteria. Indeed there are already several projects that have been proposed to relieve the constraint. However, none of these projects appears likely to be in service before 2006.

Figure 6-1
North American Pipeline Capital Expenditures
Millions of 2003 Dollars



[/1] Includes estimates for new transmission pipe, production plant hookup, cost for new underground storage, and power plant connection costs.
[/2] Includes cost of new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline, but excludes cost of gas processing plants in Alaska and natural gas liquids extraction plants in western Canada.

There is considerable uncertainty regarding the precise timing of the arctic projects. To the extent that completion of an Alaskan Gas project is delayed beyond 2013, the timing of the facilities and investment results presented here would be affected. However, the magnitude of the average annual infrastructure requirements would be relatively unchanged as long as he project is completed before 2020.

The need for interregional pipeline capacity must be analyzed from the perspective of current interregional capacities and flows and how they might change in the future.

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27 "Pig launchers and catchers" are equipment used to insert and recover "smart pigs" that are used to inspect the interior of a natural gas pipeline.

Most natural gas that is consumed is produced in different regions and must be transported significant distances to the consuming market (Figure 6-2). The largest supply regions for the United States are the Gulf Coast, both on and offshore, and Western Canada. Other smaller, but important supply areas include the San Juan Basin in New Mexico and Colorado, the Powder River Basin in Eastern Wyoming, the Permian Basin in Western Texas and Eastern New Mexico, and the Mid-Continent producing area in Northwest Texas, Oklahoma, and Kansas. LNG imports currently play a small but growing role.

By the end of the next decade, flow patterns of natural gas supply to natural gas markets will be about the same as they were in 2003. The most important supply areas will still be the Gulf of Mexico and Western Canada. However, new supply sources will emerge, such as the Eastern Canadian offshore area and new LNG import terminals (represented by the darker lines in Figure 6-3). Some other sources will increase in volume, mostly the new frontier supplies, but flows from some of the mature producing areas will decline by 2020. Incremental flows will determine where new interregional pipeline capacity will be needed (Figure 6-4).

Figure 6-2
Average Flow in 2003 (MMcf per day)

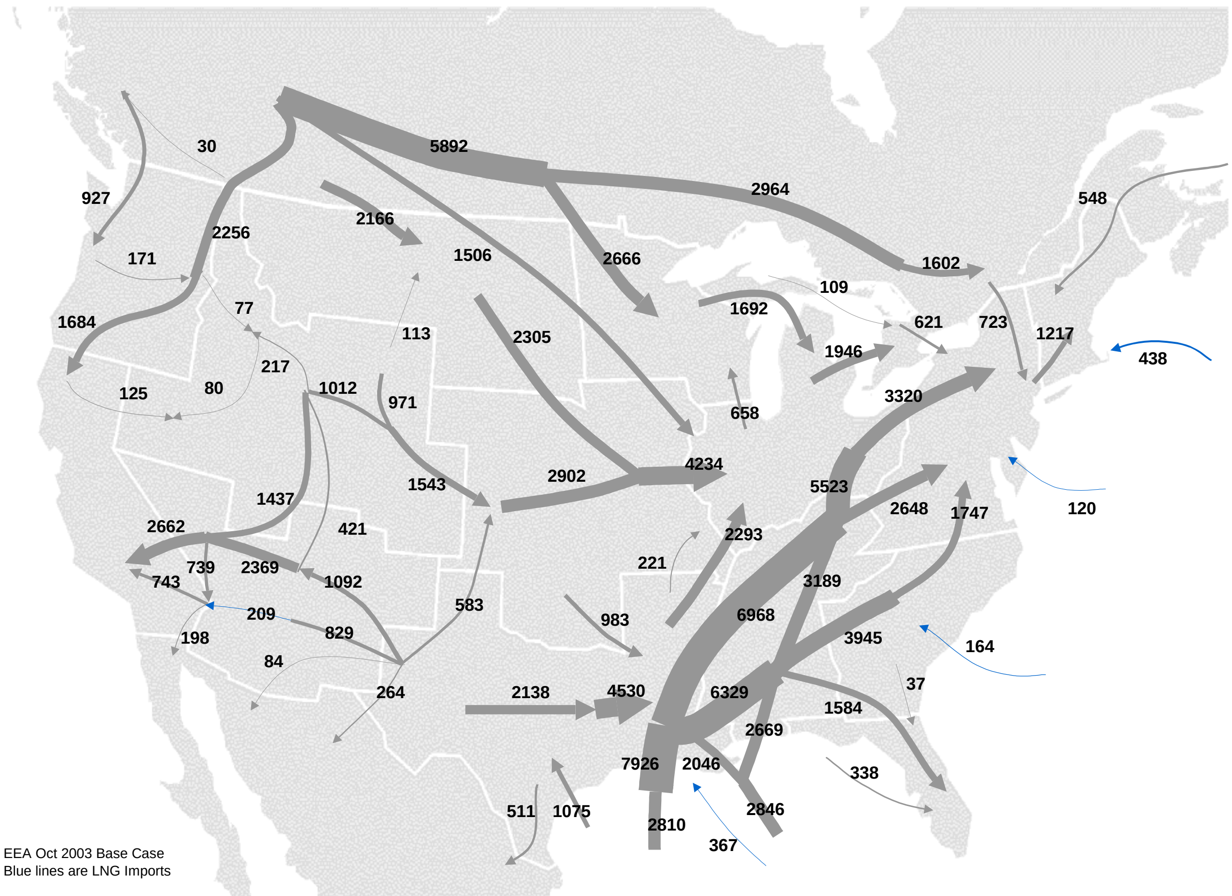


Figure 6-3
EEA Base Case – Average Flow in 2020 (MMcf per day)

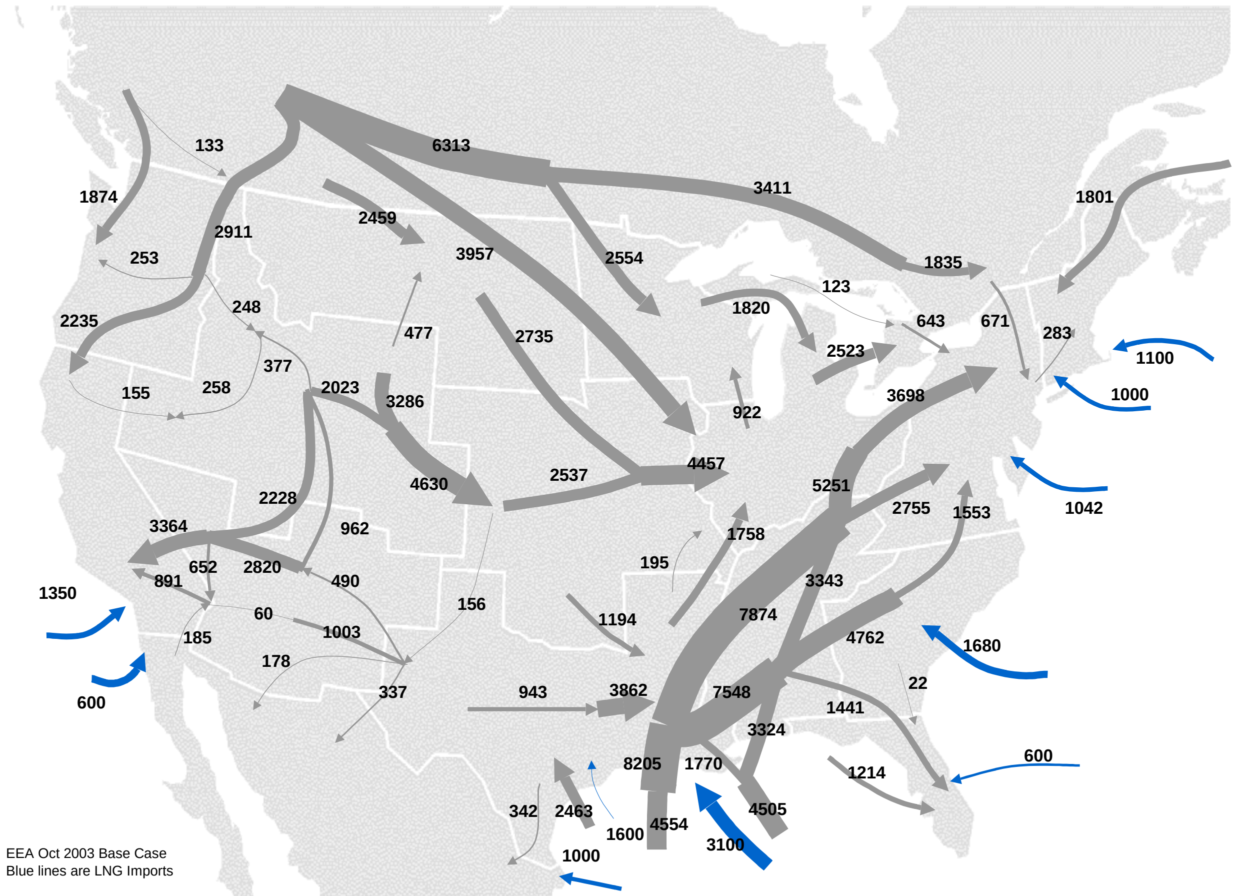
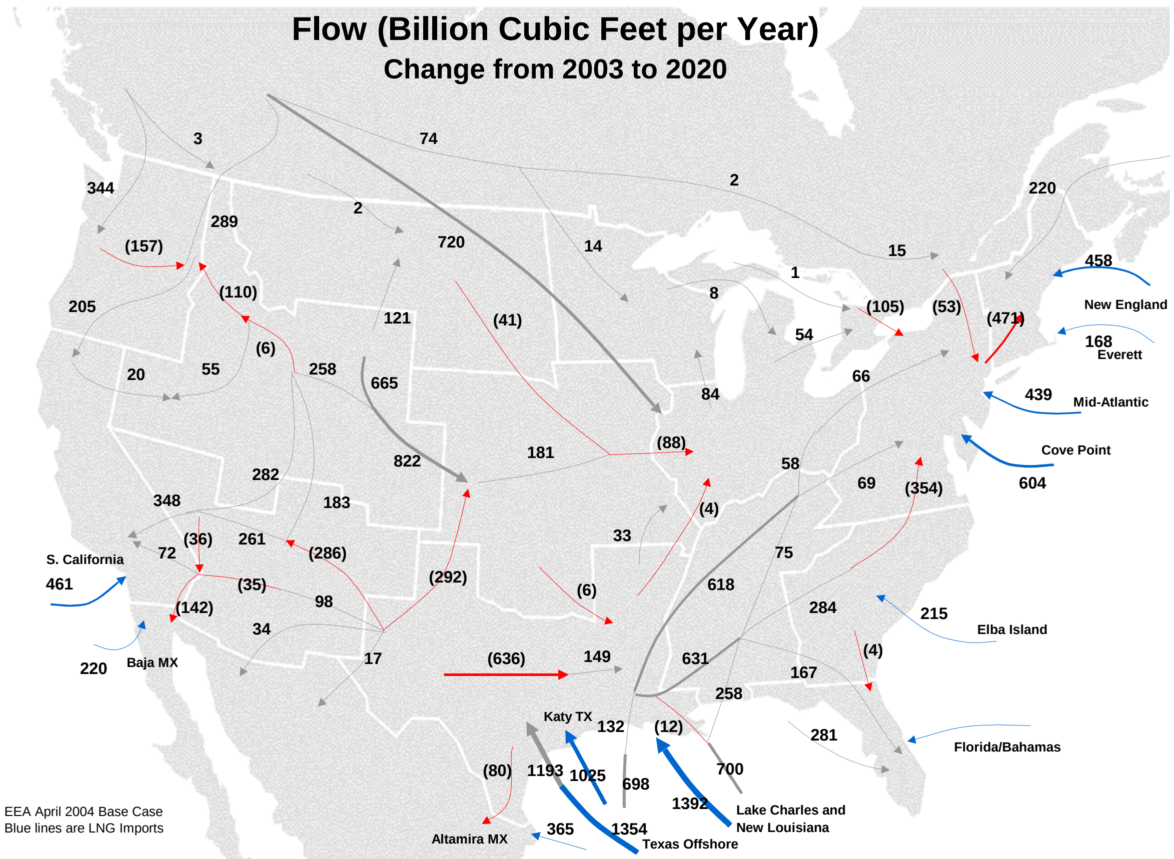
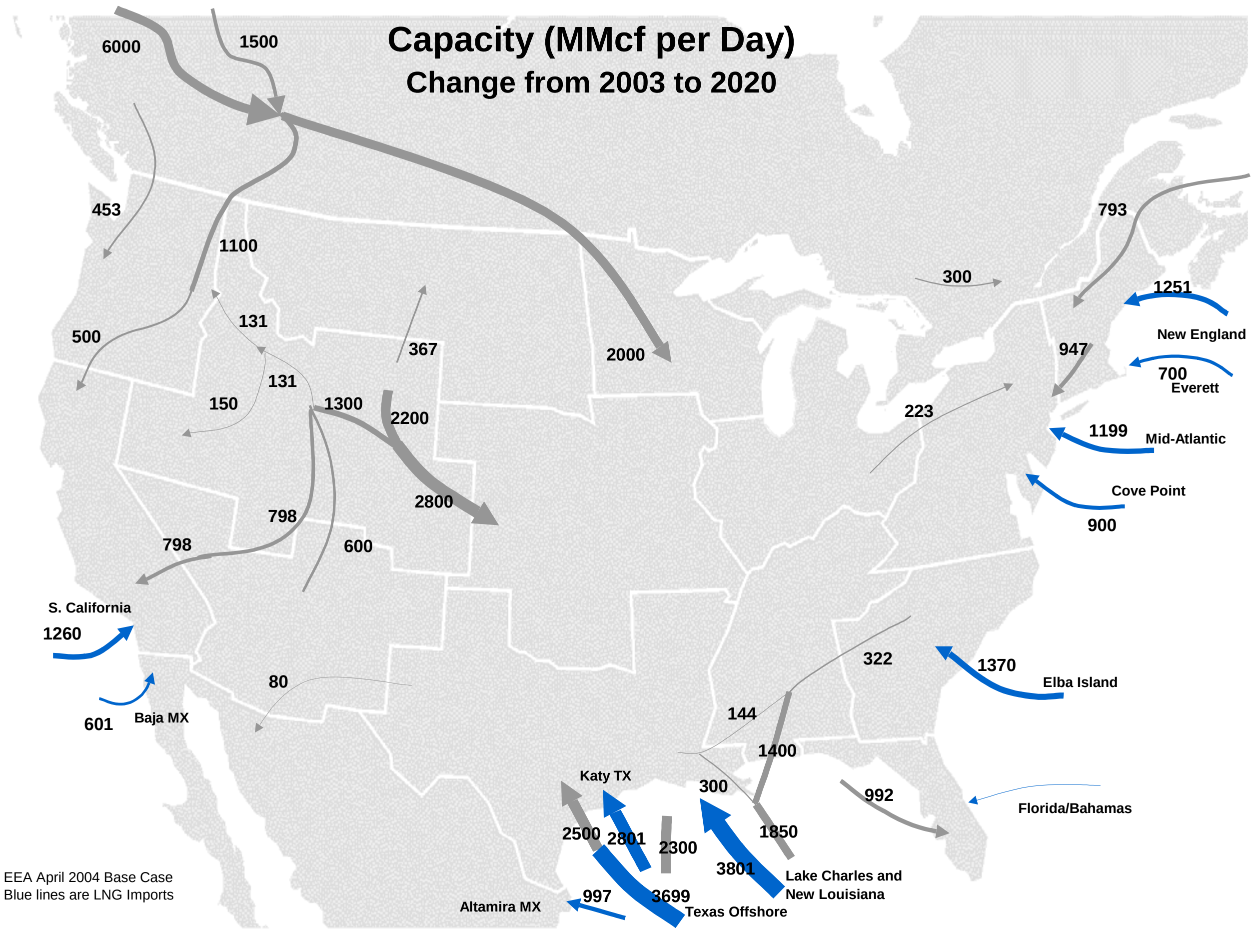


Figure 6-4
EEA Base Case – Incremental Flow 2003 – 2020



The amount of additional interregional pipeline capacity built by 2020 in EEA's Base Case is substantial. Beyond the next few years, it is difficult to specifically identify pipeline projects, but general predictions for new capacity can be made. Most of the capacity will be used to access new supply areas and the expansions correspond with the increased flows identified in Figure 6-5. In addition to accessing frontier basins, pipeline infrastructure will be needed to accommodate increased LNG imports.

Figure 6-5
EEA Base Case – New Pipeline Long Haul Capacity Requirements



From 2003 to 2020, approximately 4.6 Bcfd of additional pipeline capacity will be needed out of Western Canada. The capacity volumes are less than the forecasted 7.0 Bcfd of additional Arctic supplies entering Alberta and British Columbia from the north. This is due to existing current spare pipeline capacity, declining Western Canadian Sedimentary basin production, and increased demand in Western Canada, most notably oil sands development.

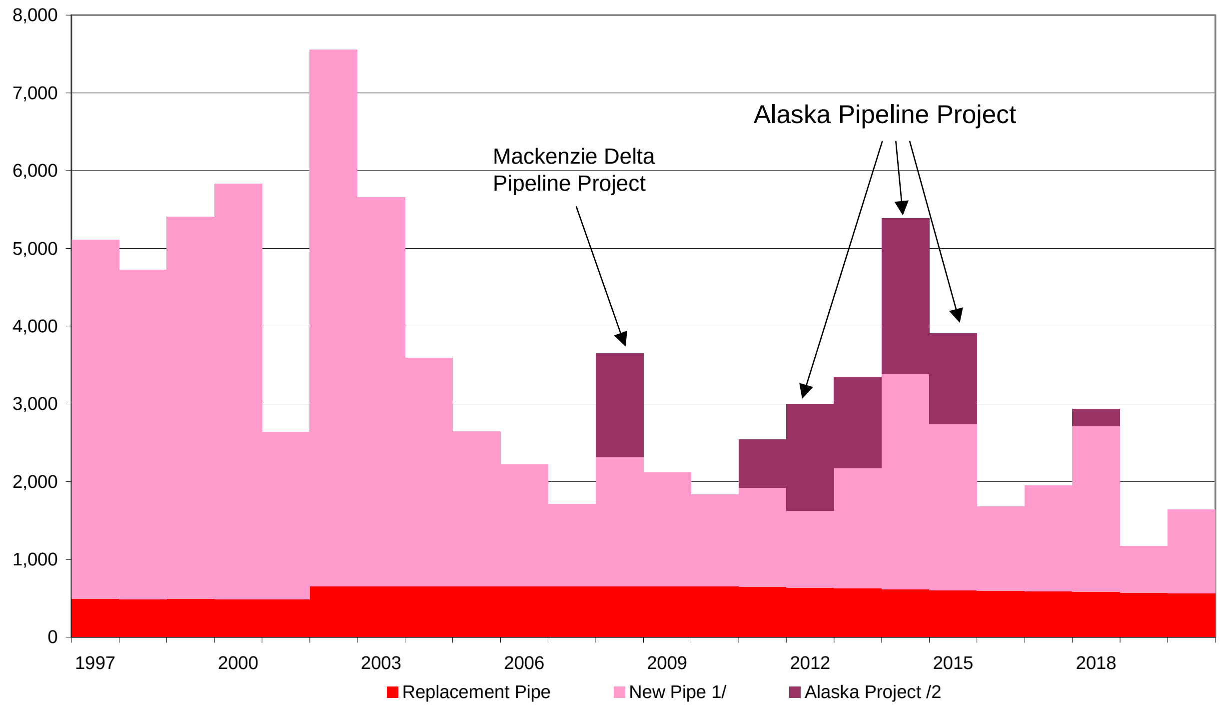
Other notable areas where interregional capacity will be needed include: 0.8 Bcfd from Eastern Canada, 5.5 Bcfd out of the Rockies, and 8.4 Bcfd out of the deeper waters of the Gulf of Mexico. In addition to the increased pipeline capacity, over 11 Bcfd of additional LNG terminal receipt capacity and the associated pipeline infrastructure to bring it to market, will be needed.

Many major supply corridors that exist today do not need expansion. For example, no increases are anticipated out of the Mid-Continent even with 3 Bcfd of additional Rockies supplies that are forecasted to enter from the Northwest. Nor are expansions anticipated in Texas to the Northeast and Midwest or along the eastern corridor. In addition projects connecting new supply basins, there will be numerous pipeline projects that relieve local bottlenecks in market areas, which are not shown in Figure 6-5.

It is important to recognize that the estimates of the amount of new pipeline capacity presented here may understate the requirements depending upon the location of the development of new LNG terminals. Recently, a number of proposed LNG projects along the East Coast have faced stiff local opposition. Projects along the Gulf Coast may be somewhat more acceptable to local populations because of their experience with other heavy industries including chemicals and refining. Additional pipeline capacity from the Gulf to Eastern markets that is not reflected in the EEA Base Case may be necessary if LNG import terminals cannot be sited along the East Coast.

Including both regional and interregional pipelines, the natural gas industry will need to install more than 45,000 miles of pipe to meet market demands for natural gas in North America. Approximately 35,000 miles will be new pipe while 10,000 miles will be needed to replace existing pipe. Of the 35,000 miles of new pipe, approximately 7,000 miles will be associated with bringing Alaskan and MacKenzie Delta gas to the lower-48. Figure 6-6 presents the estimated number of miles required by year.

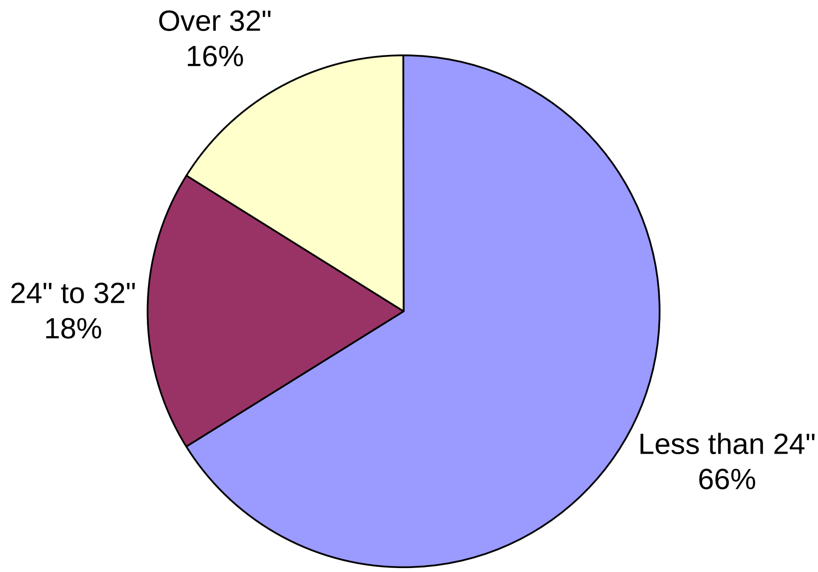
Figure 6-6
EEA Base Case – Miles of Pipeline Additions in North America



/1 Includes estimates for new transmission pipe, production plant hookup, pipe for new underground storage, and power plant connection laterals.
/2 Includes new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline.

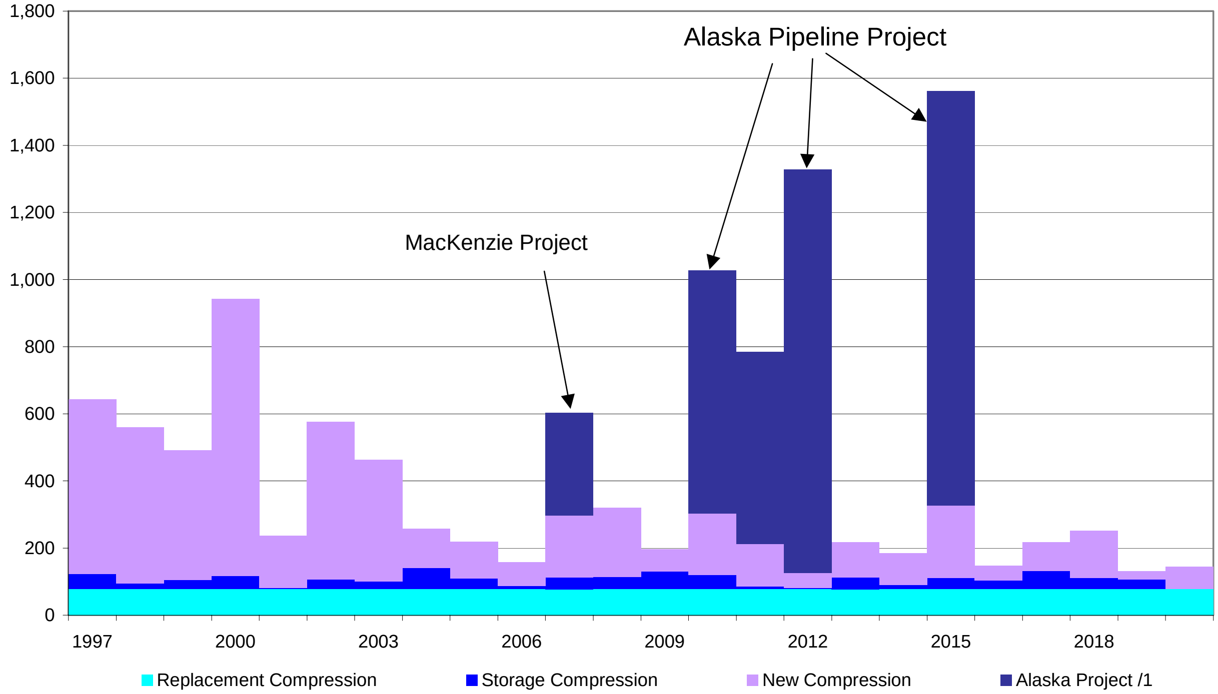
Although long distance large diameter pipes will be needed to access frontier basins, most of the pipeline built in the coming decades will be for regional needs. Approximately two-thirds of anticipated pipeline capacity built will be less than 24 inches in diameter (Figure 6-7). Such pipe will most likely be used to relieve local bottlenecks, connect new industrial customers, connect new power plants, or access new supply within a basin.

Figure 6-7
North American Pipeline Additions by Diameter
45,000 Miles added from 2004 to 2020



Along with the expected 45,000 miles of pipeline, 7.8 million horsepower of compression will be required (Figure 6-8). Approximately three-quarters of total compression additions will be associated with new pipeline projects, over 50 percent with the Alaskan and MacKenzie Delta projects. Replacement of existing compressors accounts for 17 percent of the total. The remaining 7 percent of compression will be needed in new storage projects.

Figure 6-8
North American Compression Added
(1000 Horsepower)



/1 Includes new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline.

7
CONSEQUENCES OF INFRASTRUCTURE DELAYS

The siting and permitting process for pipeline or LNG terminal construction is both time consuming and expensive. The procedure has increasingly become more complex over time. Multiple federal, state and local agency approvals are necessary before construction can even begin. Each filing agency has its own forms, processes, and data requirements. In the future this process may be streamlined in order to facilitate expeditious development of pipeline capacity or it may become even more time consuming and difficult.

Pipeline projects, by their nature, can be disruptive even though significant progress has been made to minimize both the temporary effects of construction and permanent environmental effects along the pipeline right-of-way. Routes must be selected to avoid both environmentally sensitive areas as well as urban areas. Assembly line methods of construction have been developed to shorten the stay of construction crews and restoration methods also have been improved.

Still, with any project, regardless of its market benefits, there will be different groups that will oppose it. Urban development has encroached on many existing pipeline right-of-ways. Expansions parallel to existing pipelines may be difficult to implement. There has been a ten-fold increase in protests and interventions in recent pipeline projects, compared to a decade ago. The result of this opposition to the construction of pipeline infrastructure that is economically justified is a risk that these projects would be delayed – or not completed at all.

There are a number of opportunities for opponents of a pipeline project to delay or derail a proposal. For example, despite federal jurisdiction for interstate pipelines, state proceedings in establishing the Coastal Zone Management plan, which is given federal weight by the Coastal Zone Management Act, and implementing wetlands mitigation measures. These and other permitting proceedings can allow the citizens of one state or locality to impose significant impacts on the availability and price of natural gas for citizens in a neighboring jurisdiction.

In addition, restructuring of the gas industry by Federal regulators including FERC and the Canadian NEB– and the implementation of restructuring by state and provincial regulators – have placed increasing pressure on industry participants to reduce costs. Shippers of natural gas have attempted to reduce the amount of pipeline capacity under contract to a minimum and to reduce the term of the contracts that they do continue to hold. Moreover, many state and provincial regulators have contributed to this trend by further encouraging regulated shippers – the local distribution companies that have traditional held more than two-thirds of all long-term pipeline firm transportation contracts – to minimize capacity under contract and to avoid contracting for capacity on new pipeline projects.

As now regulated, pipelines are not in a position to construct pipeline expansion projects without contractual commitments from shippers. Regulated rates of returns for pipeline capacity are not sufficient to justify “speculative” at risk construction. FERC looks upon the degree to which capacity is contracted as an indicator of market need. The certificate of public convenience and necessity under the Natural Gas Act that conveys important rights of eminent domain require that the cost of the project be covered with revenue based on firm contracts.

But perhaps as important, both regulated and unregulated shippers have become more and more reluctant to enter into the new long-term contracts that are necessary to support new pipeline and storage construction projects. Existing regulation has failed to overcome a fundamental economic "externality"[28] in the market for pipeline transportation and storage service – a so-called "free rider" problem.

When a pipeline constructs new pipeline capacity, a constraint that existed and resulted in expanded basis between the markets connected by the pipeline is alleviated until demand growth and/or supply deliverability grow to fill the new pipe capacity. Until that occurs, some of the capacity that was built will be available to be used for interruptible service (IT) or as capacity release. Often the market for that capacity sells at a discount to the maximum regulated rate for the pipeline capacity. The result is that the shippers that entered into the contracts with the pipeline that were necessary to support the construction of the project in the first place, operate with an imbedded cost structure that is at times maybe higher than shippers that rely on IT or capacity release.

This "free rider" problem provides an incentive for shippers to delay as long as possible any contractual commitment to a new project because of uncertainty regarding future prices and in the hope that it will be built without their commitment. Existing regulation including the policy favoring incremental pricing of new pipeline construction compound the "free rider" problem. The benefits of some level of "reserve" pipeline capacity to all consumers in the downstream market are not considered under the current framework and there is no mechanism to recover the costs of the "reserve."

Finally, the needs of gas-fired power generators for transportation capacity and their willingness to enter into long-term capacity contracts have not come into balance. Gas generators, particularly peaking units, are extremely reluctant to enter into firm contracts. This is due to the high per unit costs that occur when gas transportation contracts are used at a low load factor. It will be imperative to address this mismatch and identify a cost recovery mechanism for these gas shippers if sufficient infrastructure is to be developed.

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[28] In economics, an "externality" is a cost or benefit of a transaction that accrues to an individual or company that is not a party to the transaction.

Impact of Delay on Cost of Gas to Consumers

Delays in pipeline infrastructure construction impose significant costs to consumers. Delayed pipeline and LNG terminal construction will reduce the available supply of natural gas to the market. Natural gas prices will be relatively higher to all consumer groups. U.S. industrial competitiveness in world markets will suffer due to increased costs. There will be job losses in gas consuming industries. There will also be direct job losses in the pipeline construction business. With a relatively higher gas price, more coal will be dispatched to meet electric generation needs. This will affect the quantity of air emissions.

An Alternative Scenario to the EEA Base Case was constructed in an attempt to quantify the costs associated with pipeline and LNG import infrastructure delay. The Alternative Scenario assumes that permitting and siting times will increase in the future. All pipeline and LNG import terminal projects not already under construction, assumed to be those projects post 2005, will be delayed an additional two years. Major frontier projects and the associated natural gas production such as the Alaskan Gas Pipeline and the MacKenzie Delta Pipeline are also delayed two years from the EEA Base Case. All other assumptions in the EEA Base Case (economic, price of alternative fuels, weather, generating capacity, etc…) were kept constant.

Using the Henry Hub price as a proxy, a two-year delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $0.78 per MMBtu from 2005 – 2020, $0.62 per MMBtu in constant 2003 dollars (Table 7-1). Price effects will be immediate and lasting throughout the forecast period (Figure 7-1). Interestingly, there is a single year where there is a relatively lower gas price in the delay scenarios compared to the EEA Base Case. In the first year full of deliveries from the Alaskan pipeline project, a large increment of gas comes to market that provides some relief to the constrained market environment described by the Alternative Scenario. The supply shocks the supply deprived markets depressing prices, but only for the one year.

Table 7-1
Natural Gas Price Effects of a Two-year Delay in Pipeline and LNG Terminal Construction

Average Henry Hub Price Nominal $ per MMBtu

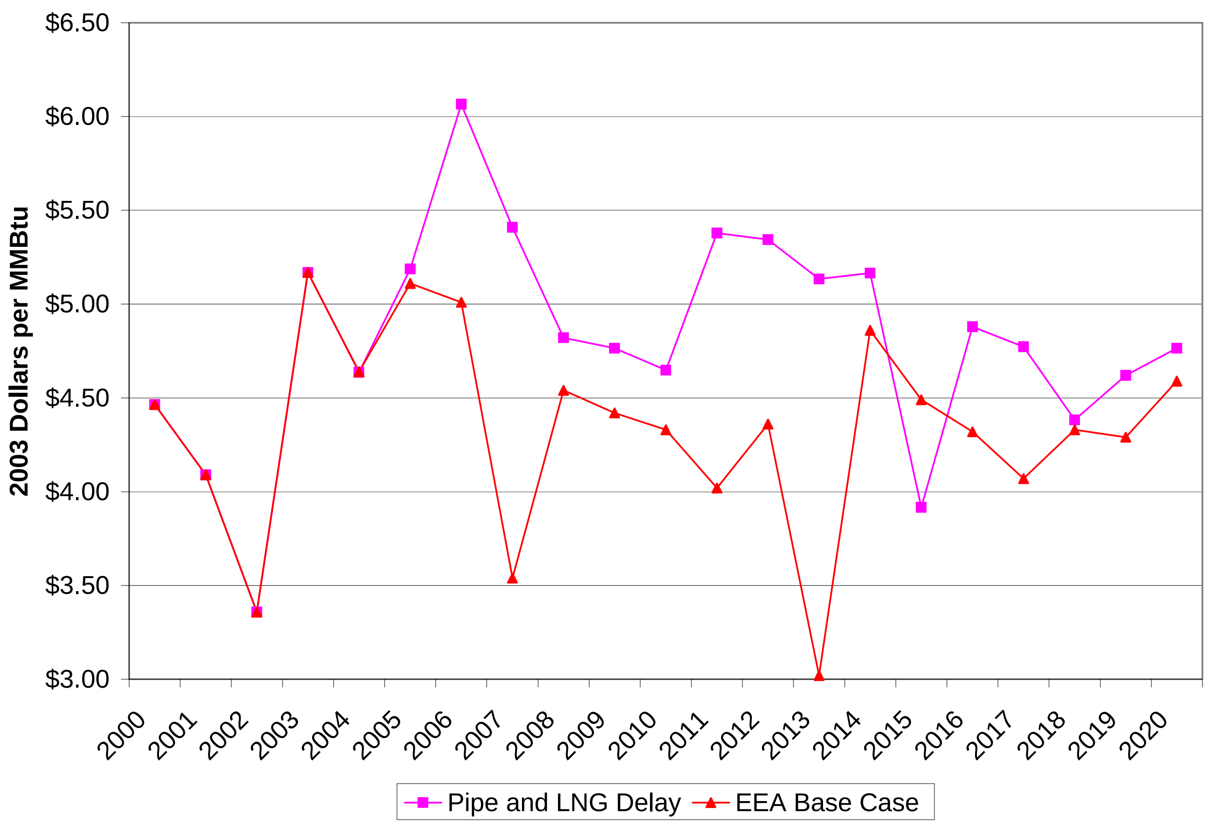
Time Period	Base Case	Two-Year Infrastructure Delay	Price Increase
2005-2010	$5.15	$5.89	$0.75
2010-2020	$5.95	$6.75	$0.80
2005-2020	$5.65	$6.43	$0.78

Average Henry Hub Price Real 2003$ per MMBtu

Time Period	EEA Base Case	Two-Year Infrastructure Delay	Price Increase
2005-2010	$4.49	$5.15	$0.66
2010-2020	$4.24	$4.84	$0.60
2005-2020	$4.33	$4.95	$0.62

Figure 7-1
Real Henry Hub Average Annual natural Gas Price

(2003$ per MMBtu)



In total, a two-year delay in natural gas infrastructure construction will cost U.S. gas consumers in excess of $200 billion (in constant $2003) by 2020 (Table 7-2). Higher gas costs will be seen in all parts of the country. Only in the Northern Rockies, (Colorado, Wyoming, and Utah) will there be a temporary, between 2005 and 2010, decline in natural gas prices and thus lower consumer costs. This is due to increased bottlenecks out of the region and growing supplies. However these declines in prices before 2010 are more than offset by increases 2011 – 2020.

Table 7-2
Consequences of Infrastructure Delays
Increase in Consumer (Burner Tip) Costs
Millions 2003$

State	Time Period 2005 to 2010	2011 to 2020	2005 to 2020
Alabama	1,339	2,319	3,657
Alaska	(8)	203	195
Arizona	1,050	2,033	3,084
Arkansas	691	1,233	1,924
California	9,705	20,086	29,791
Colorado	(250)	988	738
Connecticut	664	1,231	1,896
Delaware	286	598	884
District of Columbia	116	176	292
Florida	2,981	5,315	8,296
Georgia	1,568	3,702	5,271
Hawaii	0	0	0
Idaho	129	606	735
Illinois	3,309	5,905	9,214
Indiana	1,664	2,811	4,475
Iowa	634	1,360	1,994
Kansas	685	1,150	1,835
Kentucky	793	1,732	2,525
Louisiana	2,732	5,128	7,860
Main	400	600	1,000
Maryland	639	1,057	1,696
Massachusetts	1,432	2,757	4,188
Michigan	3,278	5,999	9,277
Minnesota	1,178	2,158	3,335
Mississippi	893	1,616	2,509
Missouri	751	1,704	2,455
Montana	213	465	678
Nebraska	278	674	952
Nevada	766	3,171	3,937
New Hampshire	95	167	262
New Jersey	2,272	3,600	5,872
New Mexico	267	598	866
New York	4,076	7,313	11,390
North Carolina	765	1,503	2,268
North Dakota	146	254	401
Ohio	2,514	4,235	6,749
Oklahoma	1,013	1,823	2,836
Oregon	822	1,550	2,372
Pennsylvania	2,161	3,274	5,434
Rhode Island	399	769	1,167
South Carolina	548	1,156	1,704
South Dakota	89	210	299
Tennessee	911	1,860	2,771
Texas	11,261	21,314	32,575
Utah	(156)	242	86
Vermont	40	67	107
Virginia	790	1,411	2,201
Washington	799	1,270	2,068
West Virginia	250	414	664
Wisconsin	1,364	2,283	3,647
Wyoming	(68)	119	51
Total U.S.	68,275	132,207	200,481

Table 7-3
Consequences of Infrastructure Delays
Increase in Consumer (Burner Tip) Costs By Sector
Millions 2003$

	Residiential	Commercial	Industrial	Power Generation	Total
Alabama	439	180	1,669	1,369	3,657
Alaska	51	58	36	49	195
Arizona	375	265	120	2,323	3,084
Arkansas	404	273	679	568	1,924
California	5,373	2,263	8,259	13,897	29,791
Colorado	322	118	150	149	738
Connecticut	457	576	233	629	1,896
Delaware	90	40	192	562	884
District of Columbia	146	146	0	0	292
Florida	125	381	293	7,497	8,296
Georgia	1,380	425	795	2,671	5,271
Hawaii	0	0	0	0	0
Idaho	182	100	217	235	735
Illinois	4,781	1,591	2,183	659	9,214
Indiana	1,742	828	2,017	-113	4,475
Iowa	780	414	696	104	1,994
Kansas	630	247	725	233	1,835
Kentucky	671	303	819	732	2,525
Louisiana	475	178	5,445	1,762	7,860
Main	11	29	130	830	1,000
Maryland	771	472	160	293	1,696
Massachusetts	1,180	609	393	2,006	4,188
Michigan	4,064	1,838	2,252	1,122	9,277
Minnesota	1,451	920	771	193	3,335
Mississippi	248	168	847	1,246	2,509
Missouri	1,017	447	513	478	2,455
Montana	206	106	79	288	678
Nebraska	407	172	287	86	952
Nevada	391	261	67	3,217	3,937
New Hampshire	75	85	73	29	262
New Jersey	2,471	1,603	210	1,588	5,872
New Mexico	360	234	-129	401	866
New York	4,170	3,511	-2	3,710	11,390
North Carolina	666	347	483	773	2,268
North Dakota	115	91	193	1	401
Ohio	3,423	1,606	2,332	-611	6,749
Oklahoma	594	296	805	1,142	2,836
Oregon	442	239	114	1,577	2,372
Pennsylvania	2,426	1,279	1,477	253	5,434
Rhode Island	195	135	-9	846	1,167
South Carolina	291	167	460	786	1,704
South Dakota	133	93	25	49	299
Tennessee	700	412	1,018	641	2,771
Texas	1,960	1,684	14,633	14,297	32,575
Utah	30	22	19	16	86
Vermont	30	29	36	12	107
Virginia	739	594	362	507	2,201
Washington	775	426	29	838	2,068
West Virginia	275	231	274	-115	664
Wisconsin	1,418	758	1,238	233	3,647
Wyoming	16	20	10	6	51
US	49,477	27,267	53,675	70,062	200,481

As significant as these impacts are, the prices produced in the alternative scenario were not high enough to eliminate growth in gas demand. While delayed, the scenario assumes that the projects are eventually constructed. In the alternative case at U.S. natural gas annual consumption is reduced by an average of approximately 450 Bcf per year. In this case demand still approaches 30 Tcf, only two years later.

If, however, government policy and public opposition to the construction of the required infrastructure prevents the facilities from being built even as much as it does in the Delay scenario, gas supplies will be unable to grow to meet market needs even at the reduced level of gas demand. In such a scenario, there could be tremendous pressure on gas prices, well above those quantified in the delay scenario or today's levels. The price levels would have to be such that customers that want gas conclude that they simply cannot afford to purchase gas. Given the integral nature of natural gas in homes, businesses, and industry, prices at those levels could hinder economic growth and the competitiveness of U.S. manufacturing.

Importance of Growing Gas Supplies to Electricity Generation and Electricity Markets

As was discussed earlier, much of the generation capacity capable of meeting growing electricity demand is gas fired. Given the lead times associated with the construction of new generation capacity, it is not realistic to conclude that there will be large additions of non-gas fired generation constructed prior to 2015.

Once all of the non-gas-fired generation is dispatched, there is no alternative to using the gas generation. At that point, power generators will pay almost any price for natural gas.[29] As a result, any increase in gas prices that result from a lack of natural gas infrastructure will be reflected in electricity prices.

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29 The FERC Staff Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices in Western Markets reached a similar conclusion.

Importance of Growing Gas Supplies to Emissions from Power Plants

New gas fired power plants have significantly lower emissions than the average for fossil-fired generation, which is dominated by emissions from coal plants. New gas combined cycle power plants have:

- SO_2 and particulate emissions 99 percent lower than average fossil fuel plants.
- No mercury emissions.
- NO_x emissions 95 percent below average fossil fuel plants.
- CO_2 emissions about 50 percent below coal plants.

Because of these lower emissions, one might expect that reduced availability of natural gas would result in increased air emissions from increased use of coal-fired power plants. There are two reasons that this does not take place in the scenarios considered for this study.

First, there is a growing regulatory effect that limits emission reductions from reduced use of coal. This is due to the increased use of emission "cap and trade" programs to reduce air emissions. Under a cap and trade program, emission tonnage caps are set for specific sectors, such as the power generation sector. Emission allowances that permit the emission of one ton of the capped pollutant are distributed to the affected sources. At the end of the control period, each source must hold an allowance for each ton of actual emissions. However, affected sources can buy and sell allowances to achieve the most cost-effective compliance approach. This means that, while emissions will not exceed the cap, they will also not generally be below the cap, since a reduction at one plant can be sold to another. Therefore, when increased utilization of gas generation reduces emissions, other plants will increase their emissions up to the level of the cap.

While this may seem counterproductive, the desired emission cap will be achieved and the increased gas generation will allow the cap to be achieved at a lower cost of emission control for the higher emitting plants. Thus under cap, the emissions do not change, but increased gas generation can reduce the overall cost of emission control, which is a societal benefit. Conversely, if gas generation is constrained, coal plants will have to run harder and the cost of control will increase. In any case, coal-fired power plants will require additional investment in pollution control equipment to make continuing reductions in emissions of NOx, SOx, and mercury to meet the requirements of existing and proposed standards while increasing their generation output. In addition, if CO2 control requirements were implemented, even larger investments in emission control or CO2 sequestration would be required.

In this study, however, even this economic benefit of gas use does not play a strong role. This is because the coal-fired generating capacity is already at full capacity utilization in this projection. Little or no new coal capacity has been built since the 1980s, while demand for electricity has continued to grow. Even at current gas prices, there is a strong incentive to run coal plants as much as possible. Although there is some construction of new coal plants during the latter part of the study period, coal capacity is fully utilized in both scenarios due to the limited available capacity and the high gas-coal price ratio.

Moreover, even gas-based generation does not change very much between the two cases. Given the limited demand elasticity for electricity, the increased gas prices have only a minor effect on overall generation. The reductions that do take place are reductions in incremental gas generation, thus having a very small effect on emissions. In a scenario with more available coal capacity, there could be more increased use of coal with the change in gas availability with a consequent increase in emission control costs.

Importance of Growing Gas Supplies to U.S. Industry

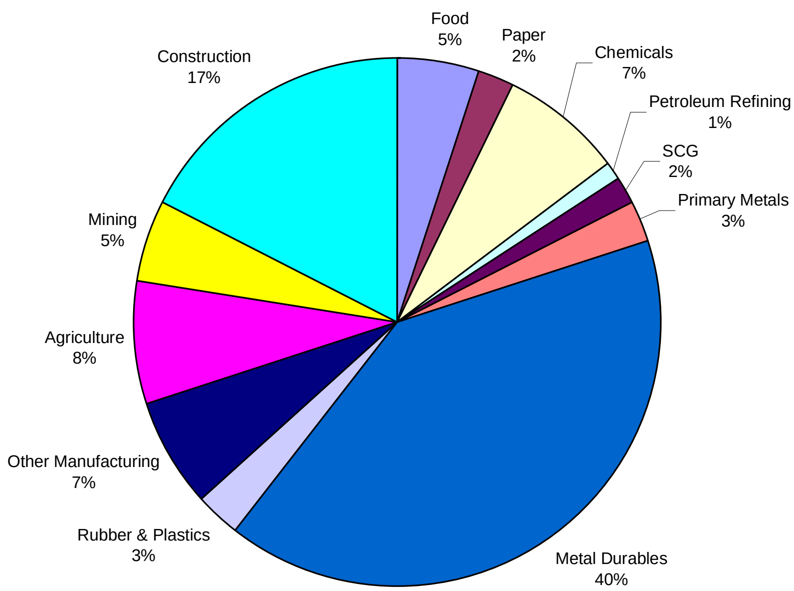
As natural gas prices have increased in recent years, there has been increasing concern over their effect on industrial sector competitiveness, jobs and the economy in general. Gas price increases in 2000-01 and in 2003 were followed by periods of economic decline and increasing unemployment. Some attribute these economic declines to the gas prices. At the same time, there is concern that high gas prices could result in permanent shutdown of gas-intensive industries, reducing gas demand. Such "demand destruction" in the industrial sector could result in lower demand for gas which could subsequently temper gas price levels and minimize volatility, though at the cost of U.S. productive output and jobs.

A study of this issue commissioned by the National Energy Commission produced several key findings regarding the impact of gas prices on U.S. manufacturing. They include:

- The industrial sector is the largest U.S. consumer of natural gas.
- Gas is a key fuel and an important feedstock for the industrial sector.
- Energy and gas-use are concentrated in a few industries. The chemicals and refining industries alone account for more than 50 percent of industrial gas consumption.
- The energy intensive industries are the basic industries, which convert raw materials into intermediate products such as steel, bulk chemicals, plastics, etc. They directly account for a small share of industrial GDP and employment. The chemicals and refining industry account for only 8 percent of industrial GDP and 4 percent of industrial employment.
- GDP and employment are concentrated in the less energy intensive industries that produce higher value finished products. The construction, metal durables and “other manufacturing” industries account for 64 percent of industrial GDP and 67 percent of industrial sector employment but only 14 percent of industrial sector gas use.

As noted above, energy consumption is largely concentrated in the basic commodity industries, which use large amounts of energy to convert raw materials into intermediate materials and may also consume energy feedstocks. However, the direct unit value of these intermediate products, such as steel, bulk chemicals, plastics, etc, is relatively low compared to finished products such as consumer goods, electronic products, etc. It is employment in these energy intensive industries that are placed at greatest risk by inadequate natural gas infrastructure development.

Figure 7-2
Industrial Sector Gross Domestic Product, 2001
2,132 Billions of Chained (1996) Dollars



Source: Bureau of Economic Analysis.

The chemicals and refining industries account for over half of industrial gas consumption and account for only 8 percent of industrial GDP (Figure 7-2). Together these industries employ over 900,000 full time workers. However, it is the less energy intensive segments of the chemical industry such as pharmaceuticals that account for most of the GDP component. While, the energy intensive and gas intensive segments of the economy are not the greatest direct contributors to GDP, they do supply many of the raw materials for the manufacturing and construction industries that constitute the bulk of GDP. As a result, a loss of competitiveness in these sectors could increase the costs of many basic materials and adversely affect the balance of trade.

Table 7-4
Industries with the Highest Shares of Natural Gas Expenditures Over Total Production Costs, 1998

Major Industry Group	Industry	Gas Cost Share	Gas Consumption (TBtu)	Employment	Value Added ($1000)
Chemicals	Nitrogenous Fertilizers	39.6 %	572	5,016	1,034,892
Chemicals	Alkalies and Chlorine	8.7 %	54	4,693	1,063,736
Chemicals	Industrial Gases	6.4 %	105	11,097	3,097,214
Chemicals	Petrochemicals	5.0 %	308	8,756	2,588,422
Paper	Paper Mills, except Newsprint	4.6 %	231	104,964	22,676,592
Chemicals	Other Basic Organic Chemicals	4.5 %	782	81,910	16,098,307
Paper	Pulp Mills	3.9 %	24	7,218	1,413,321
Paper	Paperboard Mills	3.8 %	227	48,773	11,029,318
Chemicals	Phosphatic Fertilizers	3.5 %	14	7,195	1,105,022
Food	Wet Corn Milling	3.4 %	77	8,635	2,869,704
Chemicals	Synthetic Rubber	3.3 %	55	10,340	2,437,624
Primary Metals	Iron and Steel Mills	3.3 %	494	127,359	14,375,029
Stone, Clay and Glass	Glass and Glass Products	3.1 %	159	122,504	13,679,586
Chemicals	Cyclic Crudes and Intermediates	2.9 %	50	6,771	1,349,637
Chemicals	Other Basic Inorganic Chemicals	2.7 %	102	47,584	9,224,221
Primary Metals	Foundries	2.3 %	137	199,343	16,203,518
Primary Metals	Alumina and Aluminum	2.0 %	189	76,354	8,600,132
Petroleum Refining	Petroleum Refineries	2.0 %	948	63,258	40,335,212
Chemicals	Plastics Materials and Resins	1.9 %	259	58,613	15,153,244
Stone, Clay and Glass	Cement Manufacturing	1.7 %	27	17,220	4,790,951

Source: EIA MECS and Census Bureau Annual Survey of Manufactures for 1998.

Note: Employment and Value Added values are for 2001.

There are two factors that place an industry “at risk” in the face of increased natural gas prices. They are 1) gas costs accounting for a high percentage of the total value of the product, and 2) an active and competitive world market for the end-product with robust international trade. Table 7-4 is helps identify those industries at greatest risk. The industries identified in the table had natural gas expenditures accounting for the greatest portions of total production costs in 1998. With current gas prices, the percentages have increased significantly. Importantly, all of these industries compete in “bulk commodity” industries where price, not product differentiation or branding is a primary factor determining market share. All of these basis industries would be adversely impacted to some degree by a delay in the construction of natural gas infrastructure.

The three largest consumers of gas in the industrial sector are the chemical industry, primary metals and the paper industry. Together these industries employ more than 2 million workers. In addition, all of these industries face substantial competition from abroad. The remaining energy-intensive industries account for approximately 17 percent of industrial employment. Of these, the food industry has the largest employment level, employing more than 1.5 million workers.

Industrial Sector Conclusions

From 1998 through 2003, declines in industrial sector gas demand offset the growth in power generation gas consumption to allow the market to balance in a period where gas supply remained flat. High gas prices, as well as a number of other economic factors, contributed to the loss of gas demand in the industrial sector.

If government policy and public opposition to the construction of the required infrastructure prevent the facilities from being built, gas supplies will be unable to grow to meet market demand. As a result, there could be tremendous pressure on gas prices that could hinder economic growth and the competitiveness of U.S. industry.

To balance the market without growth in supplies, industrial sector gas demand must contract. While improved efficiency can make some contribution in reducing gas demand, it would not be sufficient. Industrial activity that would otherwise occur in the United States would have to be curtailed, particularly in the manufacturing sector. If this activity is curtailed, additional manufacturing jobs will be lost.

Finally, the increases in gas prices will ultimately be reflected in the prices of U.S. manufactured goods. While this impact would be relatively small in its total impact, it would add to the direct increase in consumer costs that result from any failure to access economically viable gas supplies.

8

RECOMMENDATIONS AND FINDINGS

In order to reduce or eliminate the risk that there will be delays in the development of natural gas infrastructure costing consumers billions, three broad areas must be addressed. First, regulators at the state and federal level should consider actions that attract capital to pipeline and storage projects. In particular, state utility regulators should conduct a review of existing rules and policies that discourage state regulated local distribution companies from entering into the long-term capacity contracts for transportation and storage that are necessary to underpin new infrastructure projects.

Current state regulation often inhibits LDCs from entering into long-term contracts either actively – in the name of increasing the competitiveness of third party marketers – or implicitly through the risk of retroactive prudence review that could disallow gas capacity costs. State regulation should recognize the public benefit of capacity into a market and create a cost recovery mechanism that promotes the construction of sufficient infrastructure to allow for incremental supplies of gas to be delivered during peak demand periods. In addition, federal and state regulators should consider electricity resource planning that reflects the reliability benefits of firm pipeline and storage capacity to gas fired generation as well as alternative fuel capability.

Second, the gas industry should work with state and local officials including state economic development offices to ensure that all of the societal, employment, and consumer cost benefits of a pipeline, storage, or LNG terminal project are presented during the process of evaluating a proposed project. As part of this, public education and outreach efforts should include information regarding details of the construction process, the ultimate (post construction) impacts on the environment and safety as well as the ongoing direct and indirect benefits of construction.

Third, federal and state regulators should conduct regional analysis to identify the requirements of multi-state regions. While FERC currently conducts such reviews, the impact of these analyses could be enhanced by a process that develops additional “ownership or buy-in” of the conclusions within state and local governments. These regional analyses should explicitly consider the impact on consumers and economic development of a decision to prohibit or delay infrastructure development. The approach taken in these state and local proceedings should reflect a balance of the local impact and the impacts of the decisions on citizens in surrounding jurisdictions.

Fourth, homeland security and safety concerns, particularly regarding LNG, must be met with a balanced and informed evaluation of risk. There are many elements of modern life that present manageable risk but almost none that can be described as risk-free. All appropriate actions to ensure safety and security should be required. However, to the extent that there is any residual risk that cannot be eliminated, that risk should be evaluated in terms of the overall cost to citizens and economic security of a failure to build natural gas infrastructure that is required to meet growing energy demand.