NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States

RELIABILITY | ACCOUNTABILITY

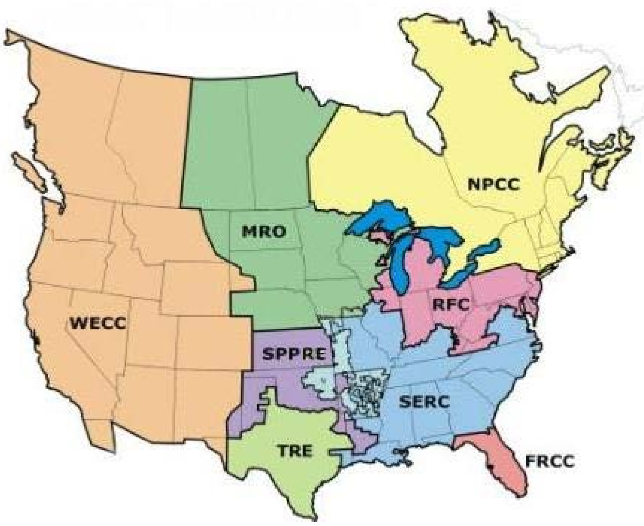



December 2011

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas as shown on the map below and listed in Table A. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries. For example, some load serving entities participate in one region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

Executive Summary

The majority of new North American generating capacity projected for the next ten years will rely on natural gas as its primary fuel. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future, overtaking and replacing coal-fired capacity. However, increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies, such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other areas, can contribute to managing this risk.

Report Highlights

Key Differences Exist
Significant events have shaped these two industries over the course of their evolution. Fundamental differences are important in understanding how the two industries plan for the long-term, communicate with each respective stakeholder, and operate within different regulatory frameworks.

Coordination and Communication
Proprietary status on most operating information significantly increases the challenge of future coordination between the natural gas and power industries. An increase of data and information sharing across the electric and gas interface will greatly enhance the reliability of the bulk power system.

Storage Solutions Diminish Interdependency Issues
The operational needs of gas-fired power plants has created day and night swings in demand for natural gas as well as weekday and weekend swings in demand.

Electric Loads Present Unique Challenges
From the perspective of the natural gas industry, it is more difficult to meet the needs of electric customers than it is to meet the needs of its residential, commercial and industrial customers. High point loads, high pressure loads, large variation loads, and non-ratable takes are major challenges for the pipeline industry. Furthermore, the electric industry has an increasing need for system flexibility.

Ample Gas Supply Expected
In terms of supply, almost all of the future growth in natural gas demand will come from the electric sector. The unprecedented growth in shale production over just the last few years, due to a combination of the prolific nature of the shale plays and the rapid increase in industry drilling activity, is expected to contribute greatly to the future gas portfolio. The shales will likely make a significant contribution to the U.S. supply portfolio for an extended period of time—potentially doubling over the next 20 years.

Pipeline Expansion to Accommodate the Electric Sector

Pipeline infrastructure planning must take into account the long-term growth of gas-fired generation. Pipeline infrastructure and capacity is expanded based on firm contracts from its consumers. Despite the growth and future expansion of pipeline capacity, more pipeline capacity will ultimately be needed to support the gas-fired capacity build out. Over the next ten years, a significant amount of gas-fired generation is projected—45 GW of Planned and an additional 48 GW of Conceptual capacity. With environmental regulations potentially causing some coal-fired base-load units to retire, gas-fired generation will likely be needed to serve more base-load demand.

PHASE I RECOMMENDATIONS

- Future natural gas storage facilities will not only have to satisfy the traditional demands for fuel supply reliability, but it will also have to satisfy the significant and expanding swings in demand for gas that can only be accommodated by high performance, multiple cycle natural gas storage facilities.

- Vital information needed for the reliable operation of the bulk power system should be shared with system operators from both industries—increased transparency in both markets is needed. Examples of this include the sharing of maintenance issues (*e.g.,* the pipeline and the generators), new facilities perceived impact, load levels, dispatch principles and general patterns or forecasts for both industries.

- Communications between two industries are hampered by the incompatibility between the traditional gas day, traditional electric day, and the market day (in market areas), which increases the difficulty of the gas industry providing the needed services to its largest consumer. Contracting practices also make it difficult to plan the flexibility needed for both industries' reliable operation. A coordinated approach for engaging the two industries to come together and develop compromising solutions to address communication strategies, operational changes, and tariff changes is critical. The two industries must reconcile the divergent views such as firm contracting needed to build new pipeline capacity and how to secure day-to-day delivery of gas.

- Vulnerabilities should be identified. Mitigating strategies should be incorporated into the planning and operation procedures for both industries. The electric industry should evaluate which generators may be most susceptible to pipeline disruptions (e.g., number of pipelines serving the generator, proximity to gas storage, and location relative to pipeline). The gas pipeline industry should consider electric system generation forecasts during the planning process. For operations, the sharing of real-time system information by both industries increases the ability for each to make informed decisions and reduce overall risk.

Chapter 1—Introduction

The North American electric power sector has transitioned from being the smallest consuming sector within the natural gas industry to the largest consuming sector. Going forward, the electric sector likely will account for the vast majority of the demand growth within the natural gas industry. Furthermore, as the natural gas industry incorporates more electric compression within its transportation systems, the interdependencies between these two critical industries continue to evolve. As a result, the need for the two industries to closely coordinate continues to grow.

The results of this report (Phase I) provide a foundation for sharing: a) preparedness in face of unusual situations, b) build on regional readiness evaluations, and c) practical steps that could lessen extreme-condition impacts and vulnerabilities. Phase II of this study will leverage this report as a platform for discussion with both industries (to be performed through 2012).

In an effort to facilitate such coordination this report takes the initial step of presenting a primer on the natural gas industry and its interface with the electric power industry. The report and its associated appendices are divided into the following sections:

- **Historical Background:** A brief summary of the critical events that have helped shape the current industry are presented in this chapter. In particular, the importance of the various FERC orders that facilitated the transition from a regulated to a deregulated natural gas industry is described. Associated with Chapter 2 is Appendix A, which presents a summary of the major incidents (*e.g.*, shortages and major weather events) that have significantly impacted the natural gas industry.
- **Structure of the Natural Gas Industry:** This section reviews each of the major segments of the gas industry from wellhead to burner tip in the structurally unbundled environment and includes a brief assessment of pipeline design for pipelines in order to provide the reader with a better appreciation of both their capabilities and limitations. In addition, an overview is presented of the recent expansion for gas pipelines. Associated with Chapter 3 is Appendix B, which reviews key elements of gas processing plants and natural gas storage.
- **Natural Gas Demand:** This section provides (1) an assessment of the natural gas consumption within each of the four primary consuming sectors (*i.e.*, residential, commercial, industrial and electric); (2) an overview of primary demand drivers for each sector; and (3) an assessment of current trends. The electric sector discussion is more extended than that of the other sectors. Also, a brief discussion of the potential gas use within the transportation sector is included.
- **Natural Gas Supply:** Each of the four major components of the North American gas supply portfolio is reviewed in this section, with most of the emphasis being on domestic production and the impact of emerging shale plays. Associated with this section are Appendices C and D, which provide regional production profiles, maps and tabulations for Liquefied Natural Gas (LNG) regasification terminals.

- **Regionality:** This section highlights the unique regional characteristics of both the natural gas and electric industries. Because of the regional differences within each industry, the challenge of coordinating between the two industries varies by region. Associated with this section is Appendix E, which presents the fuel-mix for each of the electric regions. The significant differences in market share for gas-fired generation among the regions is highlighted.
- **The Gas and Electric Reliability Interface:** This section builds upon the material provided in the other sections and examines the critical elements of the gas/electric reliability interface, as well as the challenges they present. Included in this overview is an assessment of the major characteristics of electric gas loads (*e.g.*, large, high pressure, point loads that are subject to considerable variation) and the challenges these demand characteristics present to the gas industry. Also, incorporated in this section is an assessment of communications between the two industries and the incompatibility between their traditional planning and scheduling processes. Associated with this section is Appendix F, which presents a more complete discussion of pipeline packing and the potential for large electric loads to quickly exhaust system line pack (the volume of gas used to maintain pipeline pressure and integrity) while responding to electric sector contingencies.

Chapter 2—Historical Background

In very simplified terms, the history of the natural gas industry can be divided into two eras, namely (1) a regulated era and (2) the more current deregulated era. Concerning the former, while this era of the industry has long since passed, the regulations that existed during this period of time have had a significant impact on the structure of the industry and as a result, at least indirectly affect how the industry operates today. While the electric industry is somewhat functionally unbundled, the natural gas industry is structurally unbundled. For example, separation in the electric industry in the form of deregulation, in many areas, disconnects operators and owners of different functional responsibilities (e.g., transmission, generation, distribution, balancing). In comparison, the natural gas industry remains structurally unbundled from both upstream producers and downstream consumers (e.g., transport and storage activities are separated from merchant gas activities). There are vertically integrated utilities in the power industry, while there are no vertically integrated utilities in the gas industry. This fundamental concept is important in understanding how the two industries plan for the long-term, communicate with each respective stakeholder, and operate within different regulatory frameworks.

In order to provide the reader with some perspective on this era and the structure of the industry at that time, as well as the transition into the current deregulated era, a very brief synopsis of the regulations that historically have guided the industry are provided below.

REGULATED ERA (1938 TO 1984)

In 1938, the federal government became involved directly in the regulation of interstate natural gas with the passage of the Natural Gas Act (NGA). This act constitutes the first real involvement of the federal government in the rates charged by interstate gas transmission companies. Essentially, the NGA gave the Federal Power Commission (the FPC, which had been created in 1920 with the passage of the Federal Water Power Act) jurisdiction over regulation of interstate natural gas sales. The NGA specified that no new interstate pipeline could be built to deliver natural gas into a market already served by another pipeline. In 1942, these certification powers were extended to cover any new interstate pipelines. This meant that, in order to build an interstate pipeline, companies must first receive the approval of the FPC.

The rationale for the passage of the NGA was the concern over the heavy concentration of the natural gas industry, and the monopolistic tendencies of interstate pipelines to charge higher than competitive prices due to their market power. While the NGA required that 'just and reasonable' rates for pipeline services be enforced, it did not specify any particular regulation of prices of natural gas at the wellhead.

As a result of the NGA and the subsequent 1954 Phillips decision by the U.S. Supreme Court,[2] nearly every aspect of the interstate natural gas industry, including prices, was controlled by federal regulation. The net result for the interstate market was that natural gas was sold to end users as a bundled product

[2] http://supreme.justia.com/us/347/672/case.html

(*i.e.*, supply, transportation and services were contracted for a single unit). At the time, the interstate pipelines were the only entities that could contract for natural gas supplies, with the dominant contracting practice of being able to contract for gas supplies for the life of the production field. As a result, the primary focus of the pipelines was the long-term reliability of supply, since prices, tariffs and services were fixed by federal regulation (*i.e.*, in essence it was the only issue left to manage). Furthermore, contract negotiations for gas supplies, which were abundant at the time,[3] primarily centered upon "take-or-pay" clauses,[4] as everything else was, in essence, fixed. Typically, the pipelines agreed to a minimum take obligation of 70 percent, which provided them with a very useful mechanism for managing the seasonal nature of gas demand (*i.e.*, the 30 percent of supply above the minimum requirement was available on call).

At the end user level, Local Distribution Companies (LDC's) entered into long-term contracts with pipelines (*e.g.*, 20 years) for a bundled product consisting of supplies, transportation and services (*e.g.*, storage). In this market, which was structured by federal regulation, LDC's were also able to pass through costs to their customers.

While this system worked for a while, it had one major flaw, namely the rigidity of the market structure, and in particular the low, cost-based gas prices set by federal edict, eliminated any incentive to further increase supplies, which became evident in 1976/1977. In addition, there was a key exception to the very rigid interstate market, namely the intrastate market, which eventually highlighted the inherent flaws of the interstate market.

INTRASTATE MARKETS

Federal regulation only applied to interstate commerce—natural gas sold within a state was excluded. In addition, because of the Hinshaw exemption in the NGA,[5] federal regulations could not control intrastate pipelines. The key intrastate markets for natural gas were Texas, Louisiana and Oklahoma,[6] which together represented about 70 percent of U.S. production and accounted for about 30 percent of U.S. consumption prior to 1970. Distinctions between interstate and intrastate gas were very specific and precluded any commingling of supplies earmarked for one or the other market.

A distinction between interstate and intrastate pipelines continues to persist even today. For example, intrastate pipelines did not, until very recently, post their pipeline flows and available capacity on their electronic bulletin boards (EBBs). However, market forces and evolving regulation have greatly moved them closer together.

---

[3] Natural gas supplies at the time were considered primarily to be a by-product of drilling for oil (i.e. associated gas).

[4] Take-or-pay contracts are written agreements between a buyer and seller that obligate the buyer to pay regardless of whether or not the seller delivers the good or service. Generally, this obligation to pay does not involve the full amount due for the product, and protects the seller in the event that the buyer refuses to accept the good or service when delivery is attempted.

[5] The Hinshaw exemption refers to a pipeline company (defined by the Natural Gas Act and exempted from FERC jurisdiction under the NGA) defined as a regulated company engaged in transportation in interstate commerce, or the sale in interstate commerce for resale, of natural gas received by that company from another person within or at the boundary of a state, if all the natural gas so received is ultimately consumed within such state. A Hinshaw pipeline may receive a certificate authorizing it to transport natural gas out of the state in which it is located, without giving up its status as a Hinshaw pipeline.

[6] Also, California intrastate pipeline, because of the Hinshaw exemption, was not controlled by federal regulations.

[4] MCF is one thousand cubic feet (ft^3).

While initially the contracting practices of the inter- and intrastate markets paralleled each other, over time the decline in new supplies caused higher prices within the intrastate markets. By 1975 intrastate gas prices were more than double those of the regulated interstate market (*e.g.*, \$0.44 per MCF versus \$1.10 per MCF). This steady flow of supplies to the intrastate markets and the resulting decline in interstate gas supplies became exposed in the winter of 1976/1977.[7]

REVISED REGULATIONS

The limitation of new supplies in the interstate market eventually led to the natural gas shortages in the winter of 1976/1977. The U.S. response to this shortage was to revise natural gas regulations with the implementation of the Natural Gas Policy Act of 1978 (NGPA). While the NGPA dealt with the supply side of the equation, the Power Plant and Industrial Fuel Use Act (FUA)[8] was implemented at the same time to deal with the demand side of the equation by precluding electric utilities, but not non-utility generators, from using gas in new facilities for power generation. This was corrected in 1987 and had a significant impact on the interface between the electric and natural gas industries. Lastly, the NGPA, among other things, created the Federal Energy Regulatory Commission (FERC).[9]

These revised regulations (1) preserved the regulated bundled structure for the interstate gas industry; (2) leveled the playing field between interstate and intrastate markets in the competition for new gas supplies by statutorily setting "maximum lawful prices" for the wellhead sale of natural gas; and (3) created a complex two-tier pricing system, with over 17 price categories ranging from \$0.20 to over \$6.00 per MCF. The latter was simplified for the consumer by the creation of a blended weighted average cost of gas (WACOG).

TRANSITION TO A DEREGULATED ERA (1984-1992)

Under the NGPA system there was extensive competitive bidding for new sources of supply, because of the perception that gas supplies were limited. By 1983 this phenomenon caused natural gas prices to increase so much that natural gas demand began to decline (*i.e.*, demand eventually declined 26 percent). The combination of abundant gas supplies and the Reagan-era deregulation movement enabled the Federal Energy Regulatory Commission (FERC) to take the initial step to unbundle the natural gas industry. This initial step was Order 380, which eliminated gas costs from the pipeline minimum bill. Order 380, in essence, enabled customers (*i.e.*, LDCs) to break prior commitments with pipelines and shop for the least expensive gas supplies from other states. This represented a major change in the industry's structure and quickly changed contracting practices.

The unbundling process continued in 1985 as Order 380 was followed by Order 436, which, after several legal challenges, was introduced as a compromise in 1987 by Order 500. Order 436 and 500, among other things, provided for open access transportation among interstate pipelines and started the

[7] During the very cold winter of 1976/1977 natural gas shortages emerged.

[8] The NGPA and FUA were two of the five components of the National Energy Act of 1978. The other components were the Energy Tax Act, the Public Utility Regulatory Policies Act and the Energy Conservation Act.

[9] The Federal Power Commission was reorganized by congress, creating the FERC http://www.ferc.gov/students/whatisferc/history.htm

process of unbundling gas supplies and transportation services.[10] Open access and structural unbundling mean that pipelines no longer had to sell the gas being transported, but sell only regulated transportation service. In order to ensure open access transportation service, natural gas supply purchasing was unbundled to allow for choice among suppliers.

This initial unbundling of transportation service was further enhanced in 1992, when FERC issued Order 636, which required interstate pipelines to adopt "open access" standards,[11] as well as the structural unbundling of storage from pipeline transportation and the creation of a secondary market for pipeline capacity (*i.e.*, released capacity).

These standards required interstate pipelines to offer non-discriminatory transportation service to all shippers requesting such service, provided that capacity was available. While initially each pipelines' open access rates, which were set out in their tariffs, were different, shippers' demand eventually led to increased standardization of the business protocols for transportation and the industry as a whole. The initial effort for such standardization was done by the Gas Industry Standards Board (GISB).[12] Many of the GISB business practices eventually were adopted by FERC in an effort to standardize services and protocols. Furthermore, the GISB role was taken over by the North American Energy Standards Board (NAESB).

DEREGULATED ERA (1992-CURRENT)

While the FERC effort to unbundle the industry and establish protocols took a decade,[13] many industry observers mark the beginning of the deregulated era for the gas industry with the start of the spot market for natural gas. The genesis of the spot market for natural gas started with the large volumes of gas that were released as a result of the settlements between producers and pipelines over their gas supply contracts that occurred because of Order 380 in 1984. The combination of this 'released gas' and the declining demand at the time resulted in large volumes of excess supply (*i.e.*, the 'gas bubble' or excess deliverability that lasted for about 15 years).[14]

[10] During this period prices for most new gas categories under NGPA were decontrolled (*i.e.*, January 1985), although this is somewhat academic as prevailing market prices were below regulatory price ceilings. Subsequently, in July 1987 prices for other gas categories were decontrolled and finally in July 1989 the Natural Gas Wellhead Decontrol Act was signed into law, which provided for complete deregulation of all gas prices by January 1, 1993.

[11] As a practical matter, intrastate pipelines, for the most part, always had open access tariffs.

[12] GISB was an organization of interested parties representing all segments of the natural gas industry.

[13] While the initial effort to unbundle the industry and the related court cases extended over the 1984 to 1992 timeframe, as a practical matter the fine tuning of this effort is still ongoing, as evidenced by FERC Order 637 (2000), which improved overall market competitiveness by allowing captive customers the capability to reduce their cost of holding long-term pipeline capacity, and Order 698 (2007) and Order 720, concerning pipeline requirements to post capacity and flows on their electronic bulletin boards.

[14] 'Released gas' represented the quantity of gas that pipelines were not required to take under the take-or-pay clauses of their contracts. For example, under a 70 percent take-or-pay contract, which was typical for the period, 30 percent of the supply under the contract was released to the spot market. Since the pipelines had excess supplies because of significant declines in demand due to increasing prices, at a minimum, in the early stages of negotiations, they were able to agree to allow producers to market this gas on a spot basis, in order to avoid any potential additional liability for that gas under their high priced supply contracts. The agreements over 'released gas' often involved negotiations on other items in the contracts. Over time as the pipelines completely unbundled gas supply from transportation services, settlements were reached such that the entire volumes under these historical gas supply contracts were released to producers to be marketed, for the most part, in the spot market.

One of the early successful efforts to provide a market for the growing volumes of spot gas was the 1985 bidding program implemented by Houston Lighting and Power (HL&P), which is now Reliant Energy.[15] A similar spot gas bidding program for western gas was established by the large California utilities. In addition, in 1984 the Natural Gas Clearinghouse (NGC) was formed,[16] which completed its first spot transaction for gas in October 1984 and subsequently released its first survey of monthly spot gas price quotes for ten pipelines.

Over the next several years the volumes traded on the spot market increased rapidly, as did price discovery, particularly through the trade press. For example, at the beginning of 1989 the widely followed Natural Gas Week (NGW) publication began its independent tracking of spot prices at several locations on 18 interstate pipelines. In July of that year NGW initiated coverage of the weekly spot gas prices at Texaco's Henry processing plant in Erath, LA (*i.e.*, the Henry Hub). Coverage of the southern Louisiana gas prices on a frequent basis was an important event, as supply in the area, at that time, represented the marginal source of gas, at least for eastern markets.

Probably the most significant event in creating a price disclosure for spot gas prices was the implementation of the futures market for gas on the New York Mercantile Exchange (NYMEX) in April 1990. This clearly increased the focus and tracking of the Henry Hub cash price, since the Henry Hub was the trading point for the NYMEX futures.

Furthermore, the trading between different gas hubs steadily evolved. In February 1991, NGW began its routine tracking of weekly spot gas prices at the major U.S. gas hubs, namely Henry Hub, LA; Carthage, TX; Katy, TX; Blanco, NM; and Tuscola, IL. In 1995, the Waha, TX hub was included in the NGW summary of weekly spot gas prices at major hubs. Price discovery for these major hubs was critical to understanding basis differentials between hubs and creating mechanisms for dealing with the price risk.

Observations

The creation of the deregulated gas industry has resulted in a number of improvements for customers, such as the power industry:

- **Tailored Services:** As a result of the industry's unbundling, end-use customers have the ability to tailor a wide variety of gas services and supply contract alternatives to meet their specific needs. The power industry is by far the biggest beneficiary of the change in the industry.
- **Price Discovery:** The emergence of spot market for gas has provided increased price discovery, at a number of levels, which can be key to risk management.

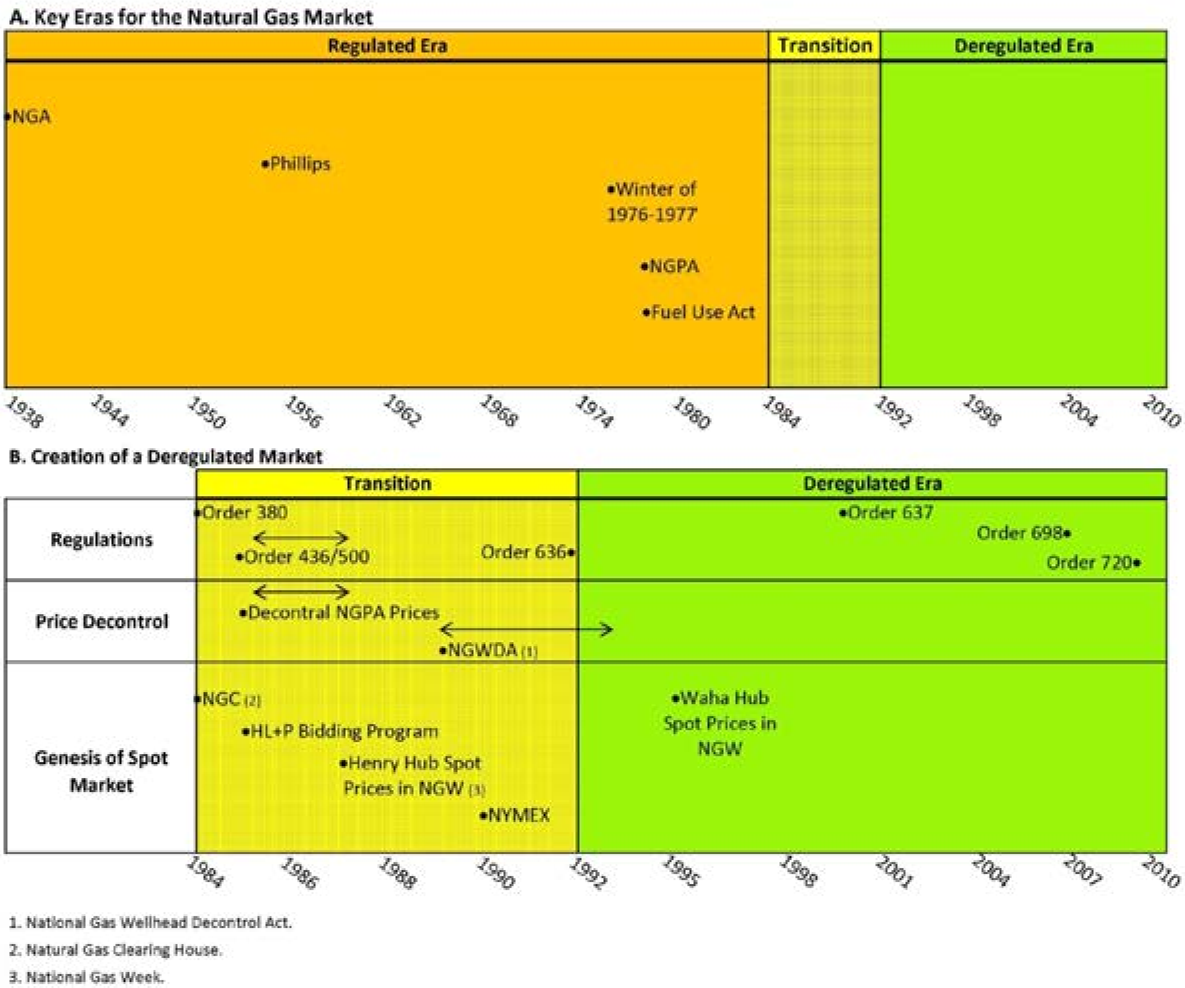
[15] In late 1985 HL&P agreed to buy, under certain provisions, at least 10 percent of its gas requirements from the spot market for gas. HL&P required a minimum of three bids for at least 150 percent of its spot gas requirements on a monthly basis. The average price of the winning bids was announced after the award of the monthly spot contracts. This bidding program was very successful and was tracked carefully by most industry participants in the region, including the trade press. In many cases the reported HL&P spot gas price began the basis for other transactions. For all practical purposes, the HL&P program represents the beginning of the widely followed Houston Ship Channel spot market gas price.

[16] This initial NGC transaction was relatively small (*i.e.*, 150 MMCFD). Also, the survey was for price quotes and not actual transactions.

- **Reliability of Supplies:** Overall deregulation has increased significantly the reliability of supplies by eliminating the possibility of natural gas supply shortages because of regulatory orders (*e.g.*, the winter of 1976/1977).[17]

Figure 2-1 provides a simplified summary of the key events in the history of the gas industry, as well as the transition from the regulated era to the deregulated era.

FIGURE 2-1: SUMMARY OF SIGNIFICANT EVENTS FROM A REGULATED TO DEREGULATED NATURAL GAS MARKET



[17] A number of countries are still suffering through natural gas shortages because of regulatory requirements.

Chapter 3—Structure of the Natural Gas Industry

The natural gas industry, unlike the electric utility industry, is highly segmented, involving several entities in the overall process of production and delivery of natural gas. These segments, despite separate competitive interests, must coordinate closely with each other in order to provide an efficient means of delivering natural gas from the wellhead to the eventual consumer (*i.e.*, the burner tip). This is one of the reasons why communication is so important within the natural gas industry. As a parallel, unbundling in the electric sector raised the same issues, raising the importance of communication between electric sector entities.

One of the reasons the gas industry is able to successfully operate under this highly segmented structure is that natural gas moves relatively slowly across the various transmission systems used within the industry (*i.e.*, about 20 miles per hour). This is in sharp contrast to the electric power industry, where the critical unit of time is much smaller (*e.g.*, milliseconds). This smaller unit of time to react to any changes has forced the power industry to be a highly integrated industry where communications are equally important, but for different reasons, and more challenging. Consequentially, the integration of these two sectors requires a slow moving product (*i.e.,* gas) to be aligned with a fast moving end product (*i.e.,* electricity).

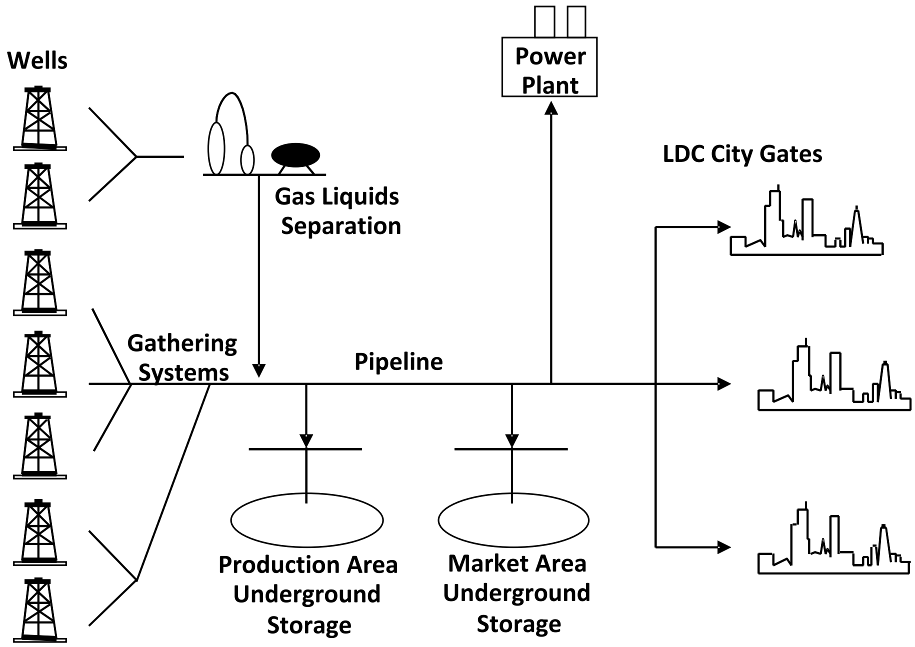
This chapter provides an overview of the various segments of the natural gas industry and how they are interconnected. Initially, a broad-based overview of all the segments is provided in order to provide the reader with an appreciation of the overall industry. Subsequently, a more detailed discussion is provided for several of the major segments within the industry.

WELLHEAD TO BURNER TIP: MAJOR STEPS IN THE DELIVERY OF NATURAL GAS

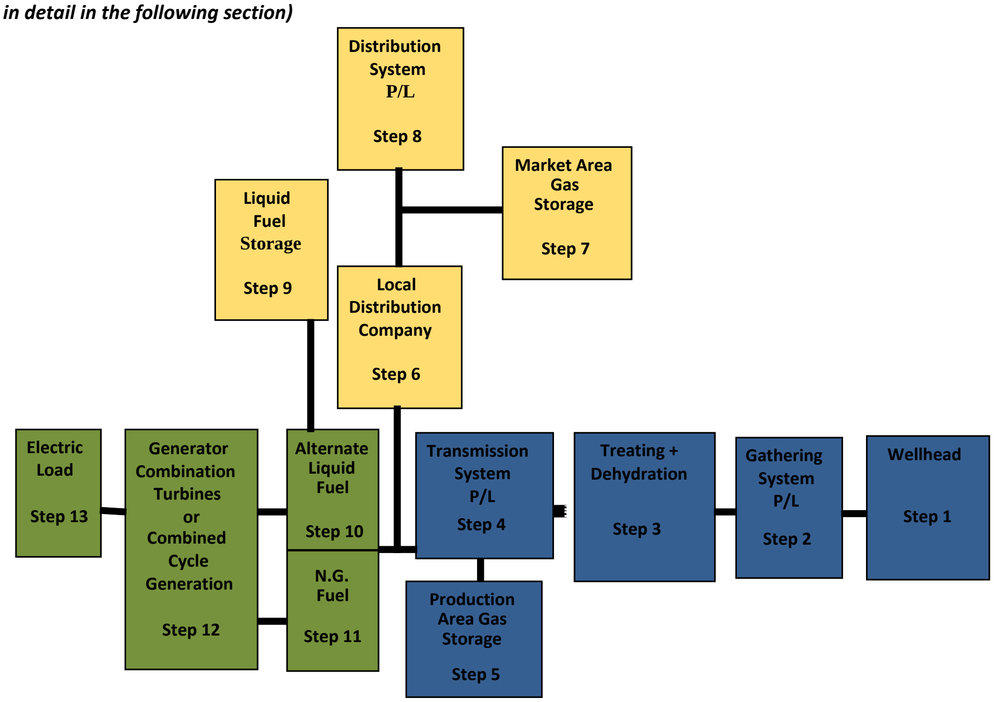
Figure 3-1 provides two simplified overviews of the segments of the natural gas industry. In the upper diagram, a simplified flow diagram is provided that illustrates the various segments of the overall natural gas delivery systems. This diagram is intended to provide the reader with a visual picture of the flow of natural gas. The lower graph is a schematic diagram for the various segments of the gas industry and includes additional details concerning a power plant consumer in order to more clearly illustrate the total natural gas/electric reliability interface. Also, each of the segments in the schematic diagram, which are numbered, is described briefly in the following material. Subsequent sections of this chapter provide further discussion for several of these segments.

FIGURE 3-1: SIMPLIFIED OVERVIEW OF THE STRUCTURE OF THE NATURAL GAS INDUSTRY

Elements of the Natural Gas Delivery System



Major Steps in the Delivery of Natural Gas from Wellhead to Burner Tip
(Described in detail in the following section)



WELLHEAD (STEP 1)

The discovery and production of natural gas is the function of several hundred explorations and production (E&P) firms within the industry. In general, E&P firms drill and maintain gas wells. Most gas is metered at the wellhead and then delivered into a field gathering system. In total, there are over 300,000 domestic gas wells. Gas delivery by an E&P firm usually ends at the wellhead. The E&P firm designated as operator of the well is responsible for the division of revenues between all joint interests and payment of royalties to land owners. Chapter 5 provides additional information regarding the natural gas supply component of the industry.

GATHERING SYSTEMS (STEP 2)

The pipelines used in a gathering system can vary in size from two inches to 30 inches in diameter, the pressure can vary from less than 20 pound-force per square inch absolute (psia) to over 1,000 psia, and the length can extend several miles. The large diameters and higher pressures are more applicable to offshore gathering systems, whereas the smaller diameters and lower pressures are more applicable to onshore gathering systems. However, there are exceptions, as some onshore gathering systems can be very large diameter pipe. Liquid and moisture build up and freezing of these lines during cold weather can occasionally cause severe operation problems. The liquid build up can be removed with the use of cleaning plugs called "pigs" (example in Figure 3-2). These pipelines may be owned and operated by either the producer or the transmission company, depending upon the contractual arrangements in effect.

FIGURE 3-2: EXAMPLE OF A CLEANING PLUG, "PIGS"

Source: www.pipeline-pigging.com

TREATING AND DEHYDRATION (STEP 3)

Raw natural gas, which is produced at the wellhead, often contains other hydrocarbons (*e.g.*, ethane and propane) and various impurities (*e.g.*, carbon dioxide and hydrogen sulfide), as well as some water.[18,19] These other hydrocarbons and impurities must be removed from the raw gas stream in order to produce 'pipeline quality' gas. This removal of other hydrocarbons and impurities is referred to as treating the gas, while the removal of the water is referred to as dehydration.[20]

While the removal of the impurities represents an additional cost in producing natural gas, the removal of the other hydrocarbons is economically beneficial, as the economic value of these other hydrocarbons is greater than that for natural gas. The removal process, which converts raw natural gas to 'pipeline quality' gas is done at a natural gas liquids (NGL) processing plant. While there are several different types of technology used at a NGL processing plant, the most common and technologically advanced is the cryogenic extracting process.[21]

There are some raw gas streams that require little, or no, gas processing in order to generate 'pipeline quality' gas. However, in all cases 'pipeline-quality' gas is odorless. As a result, for safety purposes, such as being able to detect leaks easily, a harmless odorant, such as mercaptan, is added in small quantities.

Gas processing facilities tend to serve as major collection points or hubs for onshore gas supplies. Specific examples include plants located at Henry Hub (LA), Katy (TX), Waha (TX), Blanch (NM) and Opal (WY).

GAS TRANSMISSION SYSTEM (STEP 4)

The pipelines that transport natural gas from supply regions to market or load centers are referred to as gas transmission systems, to distinguish them from gas distribution networks operated by local distribution companies. The pipelines used in gas transmission systems typically vary in size from 16 to 42 inches and can extend several hundred miles to over a thousand miles for the largest systems. The Maximum Allowable Operating Pressure (MAOP) for these systems range from 500 to 800 psia for the older systems to 1,440 psia for the new systems. Pressure that is used move the gas is created by a series of compressor stations along the pipeline route, which are typically located about 30 to 100 miles

---

[18] A raw natural gas stream consists of a variety of straight chain hydrocarbons, of which methane is the dominant component. Normally these hydrocarbons are methane (CH_4), ethane (C_2H_6), propane (C_3Hg), butane (C_4H_{10}) and some heavier molecules having five or more carbon atoms, which as a group are referred to as natural gasoline.

[19] Raw natural gas can contain a variety of impurities of which carbon dioxide and hydrogen sulfide are the greatest concern, as they are either potentially corrosive and/or poisonous. Other potential impurities can be inert gases, such as nitrogen. Pipeline quality gas is often treated to limit carbon dioxide to less than two percent, hydrogen sulfide to less than 1/4 grain/100 cubic feet, and water to less than seven pounds per million cubic feet. The removal of carbon dioxide and hydrogen sulfide from the gas stream is critical since both form acids when combined with water. Such acids are corrosive to steel pipe and could eventually cause the pipe wall to fail and leak gas. Therefore, such potentially acidic gases must be removed in a processing plant. "Sour gas" refers to the presence of potentially acidic gases and other corrosive constituents in a gas stream. The process of removing these undesirable elements is referred to as "sweetening" the gas stream.

[20] The gross heating value of any fuel is defined as the amount of heat it will produce in BTUs. For gas the pressure of the gas is given and is equal to atmospheric pressure at sea level at the temperature of 60°F. The net heating value is the amount of heat that will be available to the process. It is always smaller than the gross heating value, which accounts for the heat used in raising the temperature of the water formed in the combustion process. The gross heating value is more commonly used in the U.S., whereas Europe and other countries use the net heating value.

[21] See the Appendix for a further discussion of the various removal systems for a NGL plant and the associated technologies.

apart. The first compressor station of a pipeline is referred to as the 'head station'. Historically transmission systems, or pipelines, have been divided into two categories, namely interstate pipelines and intrastate pipelines, which as discussed in Chapter 2 is one of the legacies of the industry's regulated era.

Furthermore, the interstate systems are further categorized into major pipelines, which transport more than 50 BCF per year and non-major pipelines. There are 38 major interstate pipelines and 72 non-major interstate pipelines, as well as a large number of intrastate pipeline companies. In total, there are 233 pipeline entities, when interstate, interstate offshore gathering systems in federal water and storage companies with pipelines are included.

NATURAL GAS STORAGE (STEPS 5 AND 7)

Historically, the primary reason for natural gas storage was that it was the least expensive means of accommodating the large difference between summer and winter demand requirements. As a result, natural gas traditionally has been injected into storage fields in the non-winter months and withdrawn in the winter months to meet peak load requirements. With the growth in gas demand for the electric sector, natural gas storage is now also used to provide a variety of services for electric utilities, which can have large swings in their daily load requirements.

There are several kinds of gas storage systems, including abandoned natural gas and oil reservoirs, horizontal wells, salt dome caverns and aquifers—all of which are discussed in more detail in a subsequent part of this chapter. In addition, gas can be stored at low pressure in large above ground vessels (*i.e.*, this is very expensive and not typically used by industry) or it can be liquefied (*i.e.*, liquefied natural gas) and stored in large, insulated, above ground vessels.

Typically, natural gas storage is connected to gas transmission systems in the production area (*i.e.*, Step 5). However, for some large Local Distribution Companies (LDC), gas storage can be integrated into their systems at the market area (*i.e.*, Step 7). Either way, natural gas storage is a critical key element in maintaining both reliability and flexibility. Currently there are over 430 storage pools in the U.S.

LOCAL DISTRIBUTION COMPANIES (LDCS) (STEP 6)

Historically, the LDCs were both the largest and primary customers of the interstate pipelines. They would take control of the natural gas supplies at their 'city gate',[22] which is the point where they interconnect with an interstate transmission system, and then distribute gas supplies to the customers behind their city gate. However, with the unbundling of the industry that occurred as a result of deregulation, many of the large customers have opted to connect directly to the interstate transmission systems. This is particularly true for the power industry, as well as large industrial customers. Nevertheless, the LDC plays a vital role in getting gas supplies to the residential and commercial sectors.

[22] A distribution system, such as a local utility, connects to the interstate pipeline at a "city gate." This facility reduces the pressure of the natural gas from its transmission rate (from 200 to 1,500 pounds per square inch) down to a rate more appropriate to consumer usage (as low as 3 psi). The city gate also adds sour-smelling Mercaptan to the naturally odorless gas to make it easier to quickly sniff out a natural gas leak.

There are currently about 1,600 LDCs in the U.S., of which some are very large (*e.g.*, Atlanta Gas and Light, Peoples Gas, Dominion and the LDCs serving New York City) to very small entities serving relatively rural areas. Some of the 10 largest LDCs have their own distribution systems and access to their own storage facilities.

DISTRIBUTION SYSTEMS (STEP 8)

After receiving gas at their city gate, LDCs then transport it to their various end users via their distribution systems. Since these distribution systems are low pressure (*e.g.*, less than 200 psi), the LDCs at their city gates step down the pressure of gas supplies received from transmission companies through a set of valves and regulators. In the case of residential customers, the pressure of gas supply is further reduced when it is delivered to a home. Other customers may have need for higher pressure gas supplies. Many of those distribution systems are very old, as some were initially built over 80 years ago to primarily serve the residential market. As a result, many of these distribution systems cannot easily be adapted to meet the high pressure load requirements of electric utilities and large industrial customers. LDCs are generally not positioned to serve modern gas-fired generation because the economics favor sites connected directly to the interstate pipelines and LDCs typically have smaller lines at lower pressures. Except for several of the larger LDCs, new pipelines must be added to the overall distribution system to serve these high pressure loads. Lastly, because of their age, many of the distribution systems use cast iron pipe or seamed pipe, rather than seamless rolled pipe that is common for newer pipelines. The combination of this phenomenon and the age of such systems can lead to breakdowns of these older systems. While LDCs are constantly replacing their old pipelines, the American Gas Association estimates that cast iron pipe still represents about three percent of mileage for the LDC distribution systems.

POWER PLANT END USER (STEPS 9 THROUGH 13)

Steps 9 through 13 of Figure 3-1 represent the key components of a typical gas-fired power plant, although there are numerous differences within the industry (*e.g.*, some gas-fired power plants do not have dual-fuel capability). While electric utilities use a variety of gas-fired power generation units, the most common units in use today are the newer and larger capacity gas-fired combustion turbine (CT) and combined cycle (CC) units, high pressure gas (*i.e.*, 350 to 600 psi required for these units) and, in general, place greater requirements on the pipeline transmission system and thus, heighten the need for coordination between the gas and electric industries. While CTs usually are used as peaking units, CC units are used primarily as either cycling or base load units.

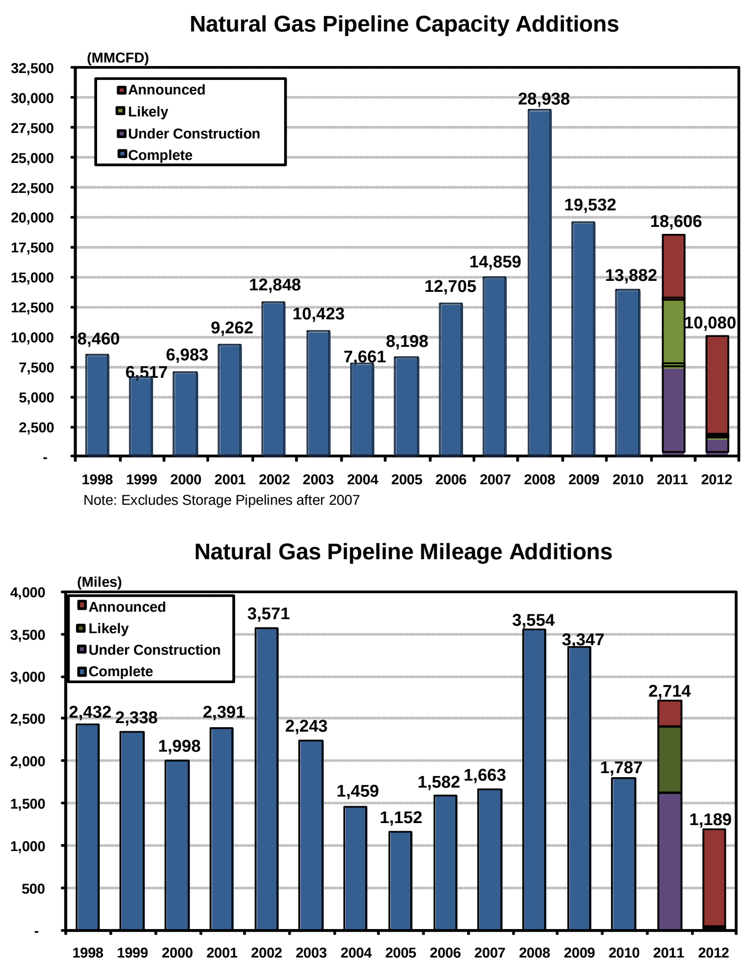
The final result of the delivery of natural gas to an electric utility is the generation of electricity. However, one of the greatest areas of uncertainty within the electric industry is the prediction of the amount of gas-fired generation required within a specified time period (*e.g.*, a day or a month) for an individual electric utility or generator. This is because the uncertainty concerning the total amount of electricity required on a given day (*i.e.*, weather changes), as well as natural gas tends to be the marginal or swing fuel, providing mid-range cycling for the entire electric power system. Thus, natural gas requirements for any given electric utility or system operator can be very dynamic.

Lastly, many modern power plants have dual-fuel units, with the alternative fuel being distillate fuel oil. The ability of the combustion gas turbine to switch fuels in less than a minute makes this kind of storage especially useful to increase reliability and provide flexibility. However, air permits for many modern gas-fired units often reduce the ability to use this alternative fuel to only emergency situations and not all fuel switching can be accomplished within a short timeframe. Even in the case of older plants, environmental restrictions greatly impact the ability to switch fuels. Additionally, for many units, fast fuel switching is not possible and may take hours for the unit to be configured to switch fuels. Consequently, not all dual-fuel generating capacity strictly negate interdependency issues.

Gas Transmission System

Large interstate and intrastate pipeline transmission systems represent the backbone of the natural gas industry. Among other things, this extended period of expansion which is summarized at the national level in Figure 3-3 will provide both increased reliability and diversification of gas supplies to end users and to the power sector, shown in millions of cubic feet per day (MMCFD) and by pipeline miles.

Figure 3-3: Comparison of Current Gas Pipeline Expansions with Historical Results



PHASE I (2007-2010)

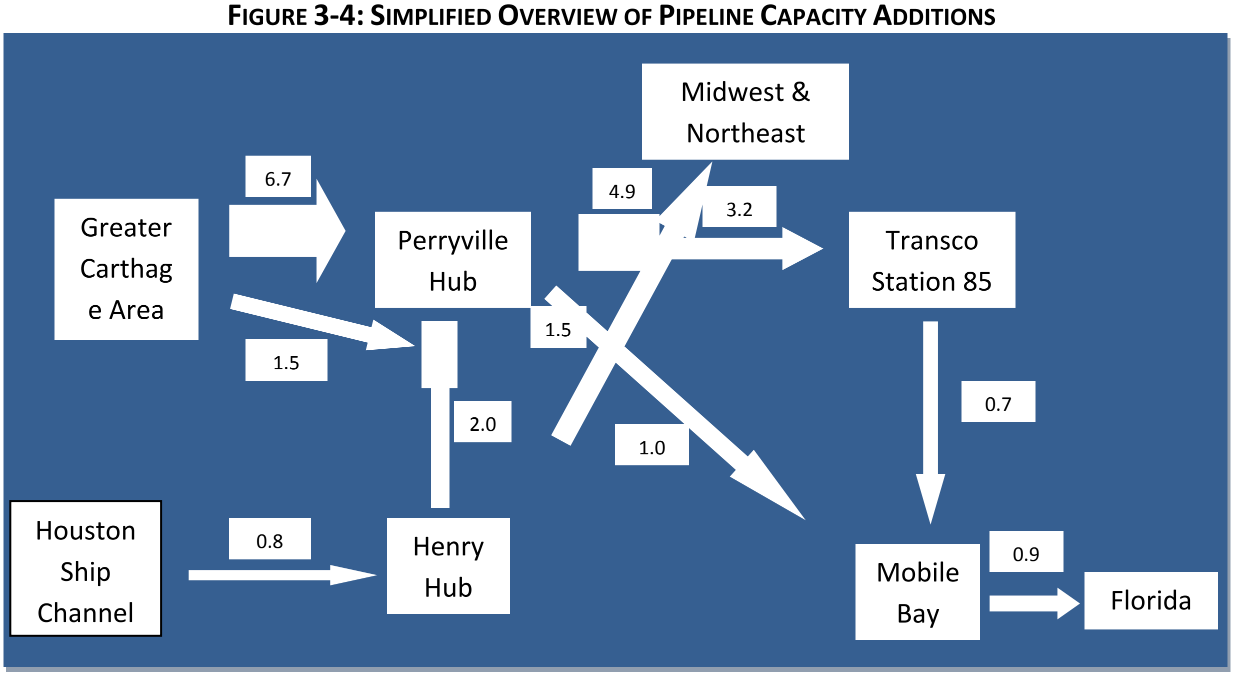
In simplified terms, the current expansion of the industry's infrastructure can be divided into two phases, although it is difficult to define a single demarcation point between these two phases.

Concerning the first phase, the primary drivers for this recent expansion in pipeline capacity were the significant growth in Rockies gas production that occurred over the prior decade and the rapid increase in the Barnett shale-gas which started production in about 2005. Also, contributing to this phase were the initial increases in production from the Fayetteville and Woodford shales.[23]

By far the standout for this phase of expansion was the 1.8 billion cubic feet per day (BCFD) Rockies Express Pipeline (REX) which, in essence, connected the nation by transporting supplies from Opal, WY to the Northeast (*i.e.*, Oakford, PA). However, there were also significant expansions elsewhere in the U.S., including the Southeast. Included in the expansion throughout the Southeast were six new pipelines (*i.e.*, 8.6 BCFD in total) and five major expansions of existing pipelines (*i.e.*, 5.1 BCFD in total). While some of these systems interconnected with each other, unlike the REX system, this still represents a significant increase in infrastructure, particularly since the above excludes several small pipeline expansions and a host of supporting projects in the Southwest that were supply conduits for the above mentioned major pipeline projects in the region.

In order to illustrate the significant increase in the Southwest's infrastructure during Phase I, the schematic diagram contained in Figure 3-4 summarizes, along major corridors, the net addition in pipeline capacity for the region. One of the significant results of this expansion to date is that physical flow of gas through the Perryville/Delhi hub is now about four times that of Henry Hub.

FIGURE 3-4: SIMPLIFIED OVERVIEW OF PIPELINE CAPACITY ADDITIONS



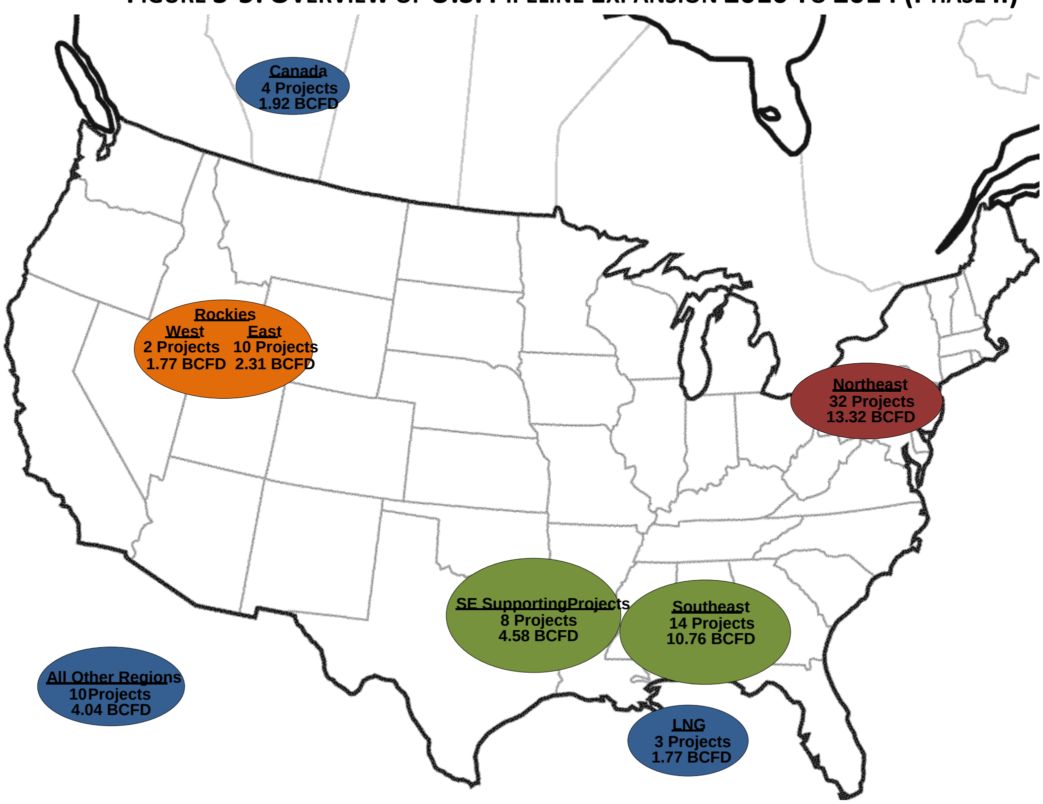
[23] See Chapter 5 for a more complete discussion on sources of gas supply.

PHASE II (2010-2014)

At present, the industry is going through the second phase of this increase in industry infrastructure. The primary drivers of this second phase of pipeline expansion are the growth in the Haynesville and Marcellus shale plays, as well as, but to a lesser degree, the Eagle Ford shale play.[24] While the online dates for some of these projects is debatable, Figure 3-5 provides a simplified overview of the Phase II expansion projects included in Phase II. There are 83 projects totaling about 40 BCFD of capacity included in Figure 3-5, with approximately 65 percent included in the following two regions:

- **The Northeast:** Most of the pipeline expansion projects in the Northeast are driven by the rapid development of the Marcellus shale play.
- **The Southeast:** The Southeast region has been divided into two categories, namely (1) the Louisiana to Georgia area, where most of the major pipelines are being constructed; and (2) Texas, where, in general, a series of supporting or feeder pipelines to these major pipelines are being built. The key driver behind this second wave in pipeline activity is the rapid growth of the Haynesville and Eagle Ford shale plays.

FIGURE 3-5: OVERVIEW OF U.S. PIPELINE EXPANSION 2010 TO 2014 (PHASE II)

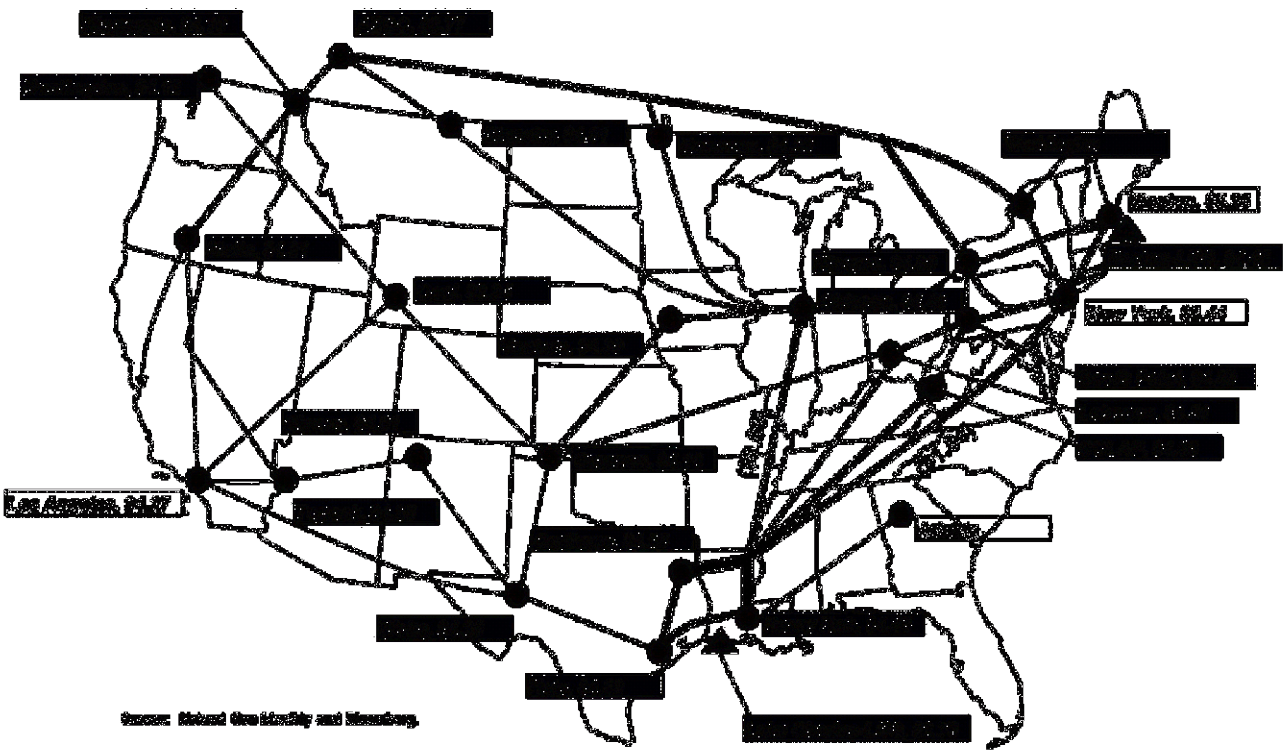


[24] The term "play" is used in the oil and gas industry to refer to a geographic area which has been targeted for exploration due to favorable geoseismic survey results, well logs or production results from a new or "wildcat well" in the area. An area comes into play when it is generally recognized that there is an economic quantity of oil or gas to be found. A shale gas play, such as the ones mentioned above, is simply a discovery of oil or gas in shale rock that is significant enough for oil and gas companies to launch a campaign of leasing and subsequent exploration. In the case of the Eagle Ford shale it is turning out to be both a shale gas play and an oil play.

GAS HUBS

While there is no precise definition of a natural gas hub or market center, gas hubs provide two significant functions for the industry, namely (1) a location with enough transportation and other services to support the needs of the market (*i.e.*, liquidity) and (2) the price transparency for gas supply in the area. Because of the latter, gas hubs have become critical in determining basis differentials, which is a key component of the total delivered costs of natural gas supplies.[25] As was noted earlier in this chapter, the major NGL plants near, or at the head compressor station for major transmission systems form some of the major hubs within the U.S. gas industry. While in the early phases of the deregulated era of the natural gas industry there were only a limited number of gas hubs, the industry has advanced since then. At present, there are over 90 gas hubs in the industry, with each fairly important within its region. In order to provide the reader with some perspective on this phenomenon, Figure 3-6 highlights most of the major hubs within the industry.

FIGURE 3-6: AVERAGE 2010 NATURAL GAS PRICES AT MAJOR HUBS AND CITY GATES



STORAGE

While pipeline line pack does allow for some flexibility of natural gas deliverability, storage is the primary vehicle by which the industry can provide the flexible services required by the power industry. As a result, access to natural gas storage, whether it be direct or indirect, is critical to most gas-fired power plants within the electric industry.

[25] Within the U.S. gas industry basis differentials are defined as the difference between the selected gas hub's gas price and the price of gas at the Henry Hub, which is the reference point for the NYMEX futures.

The material below briefly summarizes the following:

1. The key roles of storage within the natural gas industry;
2. The transition of storage from a bundled regulated asset to a commercial asset that is, in part, designed to meet the needs of the power industry; and,
3. The various types of storage facilities.

Chapter 7 addresses in more detail the gas/electric reliability interface and the various types of storage services that are important to the power industry.

INITIAL YEARS

Historically, the primary role of natural gas storage was to meet the seasonal load requirements of the major market areas. This initial application was to ensure both the reliability of natural gas deliveries during the winter season and to reduce the overall cost of natural gas deliveries to distant market centers. The latter illustrates the initial economic value of storage for those markets that are distant from major production areas. Even in its early days the industry quickly determined that it was cost prohibitive to build long haul pipelines to meet peak day requirements within a market area, as during the non-winter months the use of these assets would be very low. For example, in the residential sector, which represents about 22 percent of total primary gas demand, winter demand can be a factor of 7 greater than summer demand and in some regions it can be a factor of 16 greater. Similar conditions exist for the commercial sector, which accounts for an additional 14 percent of total primary gas demand.

As a result, each pipeline sought the right mix of pipeline and storage assets to minimize its capital requirements while still meeting peak day demand. Even today this economic attribute of storage is still significant, as many customers, including power generators, seek to use storage to minimize overall gas transportation costs and hedge against current market conditions. Similarly, the reliability attribute of storage remains a critical factor for many of today's users of storage services.

While the first underground storage was built in 1915, it was not until the 1940's when the U.S. industry began to add significant storage capacity. Between 1945 and 1975 working gas in U.S. storage fields increased from about 0.2 trillion cubic feet (TCF) to approximately 2.5 TCF. There was another sharp increase in storage capacity following the winter of 1976/1977, when U.S. gas deliveries were curtailed as a result of the combination of severe cold weather, a byzantine regulatory framework and inadequate gas supplies. After that disastrous winter the industry expanded existing facilities and built new ones, particularly in the market area. This caused underground working gas capacity to reach over 3 TCF with storage capacity at approximately 4.1 TCF.

EVOLUTION

In addition to the winter of 1976/1977, there have been three significant events critical to reshaping the storage segment of the gas industry from being primarily a seasonal reliability tool to being a commercial asset that provides a variety of functions for the industry. The other events, which were discussed in Chapter 2, were:

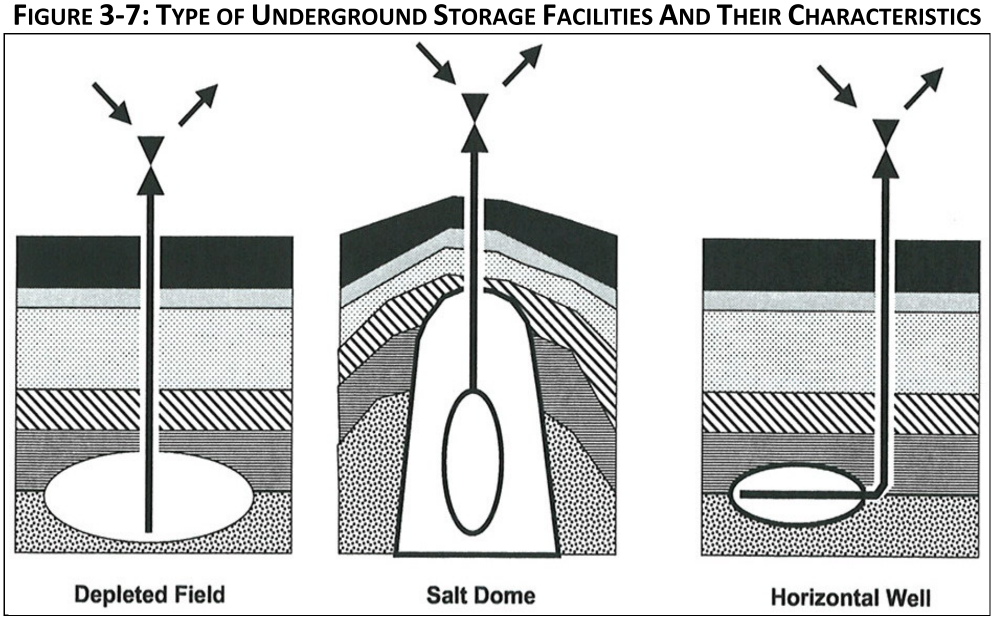
- FERC Order 636 in 1992, which unbundled the transportation and storage segments of the industry;
- The creation of the NYMEX futures for natural gas in 1990, which enabled the industry to establish the economic value of storage; and,
- The rapid expansion of gas-fired units during the 2000s (over 200 GW).

This conversion of the storage segment to a commercial asset has allowed storage operators to provide a series of hourly, daily, monthly and annual services that are of value to the gas and electric industries, while still providing the reliability function the industry needs to meet winter seasonal requirements.

TYPES OF STORAGE

There are several types of storage fields and the technology for developing them is still evolving. Underground storage fields can generally be divided into four broad categories: depleted oil/gas fields, aquifers, salt dome caverns and horizontal wells, with depleted fields and aquifers having several similarities. Figure 3-7 provides a simplified illustration of the various types of underground gas storage fields. The type of storage services that are available from a specific gas storage field are heavily dependent upon the type of storage field and its physical characteristics.

FIGURE 3-7: TYPE OF UNDERGROUND STORAGE FACILITIES AND THEIR CHARACTERISTICS



While the discussion below briefly describes the basic geology and major characteristics of each category of storage, the two categories of greatest importance to power generators are salt dome caverns and horizontal wells, because of their ability to provide load following services.

DEPLETED FIELDS

Prior to 1990 most underground storage facilities were constructed by interstate pipelines for the primary purpose of meeting the peak winter season demand of LDCs. In most cases depleted oil and gas fields were converted into storage facilities using vertical wells and they were mainly located in or near the market area adjacent to the major load centers.[26] Typically these storage fields had relatively large capacities and were designed to be cycled only a single time per year (*e.g.*, a 200 day injection cycle and 60 to 100 day withdrawal cycle). This approach provided LDCs storage gas that could be withdrawn during peak demand periods.[27] This basic storage service was integrated or bundled with other pipeline services.

AQUIFER

Aquifer storage, which is done in a porous rock formation that previously contained water under pressure that was trapped either structurally or stratagraphically, is primarily located in the Midwest. Aquifer storage for natural gas is similar to depleted fields, except that it is possible to get one and one-half to two cycles per year from such a facility.

SALT DOME CAVERNS

As has been the case with nearly every other segment of the gas industry, technology has had a significant impact on developing new storage services. Traditional depleted storage facilities have large capacities (field sizes) but are rather limited on their withdrawal capability (deliverability) and can, for the most part, only be used once per year (*i.e.*, a single cycle). New fields relying on salt caverns emphasize high deliverability and can be cycled 10 or more times per year. However, salt caverns tend to have relatively small capacities and relatively high construction costs. The ability to cycle salt dome cavern capacity can result in lower unit costs for total facility throughput, which offsets the higher initial cost of the facility. While salt dome cavern storage has been used for some time in the production area, the new dimension of this storage technology is its use within the market area.

Salt caverns for natural gas are cavities created by mining underground salt deposits. A very common type of salt cavern in many Gulf States is salt dome caverns formed in salt diapirs.[28] The other method of forming a salt cavern is from bedded salt deposits. This latter tends to be a horizontal container and is often more of an engineering challenge to complete than the vertical salt dome cavern. Bedded salt deposits are more prevalent in regions away from the Gulf States.

HORIZONTAL WELLS

One of the more recent advances in gas storage technology is the application of horizontal drilling for natural gas storage. This approach, which is referred to as Salternatives™, provides both high deliverability and large capacity (*i.e.*, a combination of the main features of depleted traditional storage

[26] At present about 80 percent of operating U.S. storage facilities are depleted oil and gas fields.

[27] Winter residential demand is typically seven times greater than summer demand and, in some regions, can be 16 or more times greater than summer demand.

[28] Salt diapirs are bodies of salt that have punctured and migrated towards the surface through other strata, since salt is less dense and more plastic than other types of sedimentary rock.

fields and salt dome storage) while extending the range of suitable sites beyond the restricted geographical conditions of salt domes. This approach has been used for fields in Oklahoma and in New York, as well as elsewhere.

ABOVE GROUND LNG STORAGE

Above ground liquefied natural gas (LNG) facilities are used to supplement upstream storage services. These facilities are distinctly different from the LNG regasification terminals that are used for importing LNG. However, in the case of New England, LNG is trucked from the regasification terminal to these above ground LNG facilities, which are designed to be used only once per season.

STORAGE FOR ELECTRIC RELIABILITY

Gas-fired power plants generally require some type of balancing service. The most common means of obtaining this balancing service is through direct, or indirect, access to gas storage. Additionally, gas-fired power plants, because of the size and variability in their load requirements, require both accesses to storage more than once per year and storage fields with high withdrawal rates. The growth in gas fired electric generation is creating a significant new gas demand peak in the summer while at the same time winter peak demand for natural gas continues to grow. In addition, the operational needs of gas-fired power plants has created day and night swings in demand for natural gas as well as weekday and weekend swings in demand—increasing wind and solar generation contribute to the complexity and must be considered in the long-term plans. Therefore, the future of natural gas storage facilities is that storage will not only have to satisfy the traditional demands for fuel supply reliability, but it will also have to satisfy the significant and expanding swings in demand for gas that can only be accommodated by high performance, multiple cycle natural gas storage facilities.[29] As summarized in Figure 3-8, the salt caverns, as well as horizontal well technologies, have these characteristics.

FIGURE 3-8: GENERAL CHARACTERISTICS OF VARIOUS TYPES OF STORAGE

	Gas Withdrawal Rate	Gas Storage Volumes	Gas Storage Cycling Capability
Above Ground LNG Storage	Low-Medium	Large	1X
Aquifer	Low-Medium	Moderate	1X-2X
Salt Dome Caverns	High	Small	5X-10X
Horizontal Wells\Depleted Fields	High	Large	5X-10X

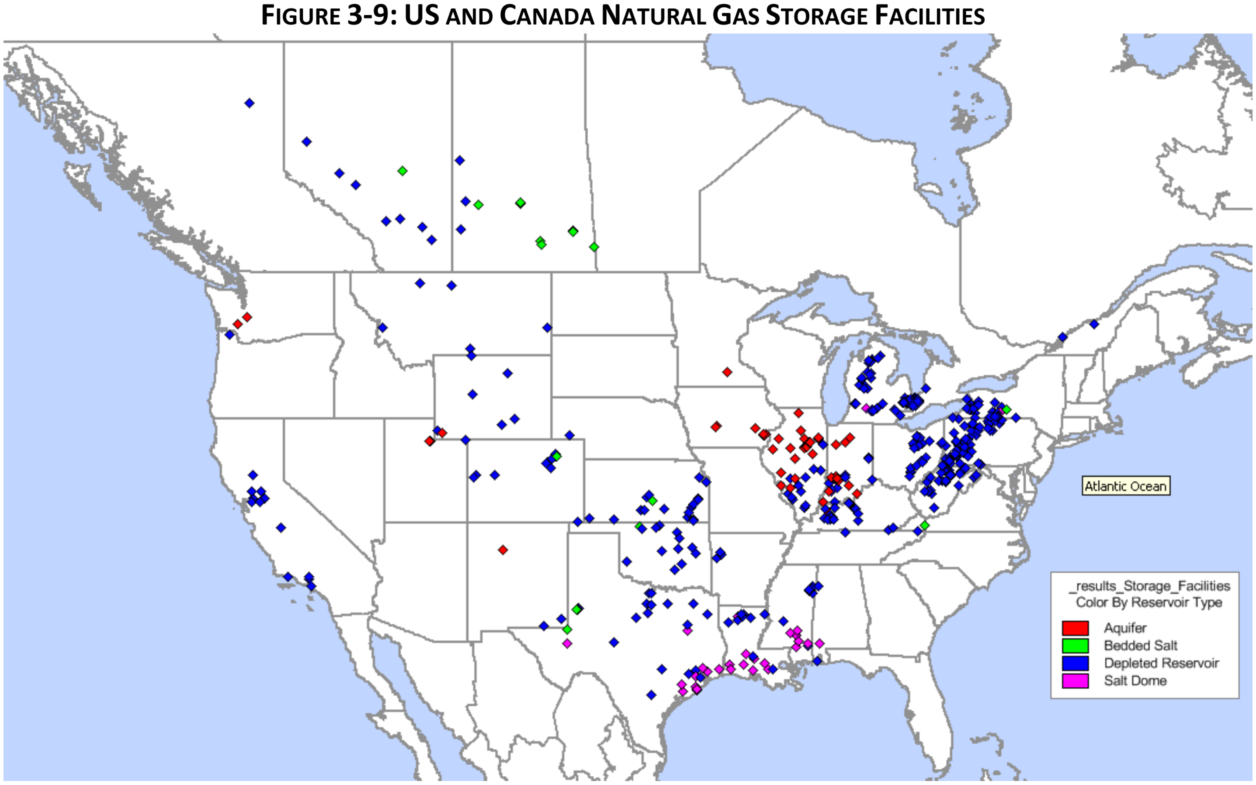
[29] Cycling refers to the storage facility's ability to complete the injection and withdrawal of Working Gas. Traditionally reservoir storage is designed to complete one cycle in each year. Recent market trends have produced the need for storage facilities capable of completing multiple cycles per year.

STORAGE CAPACITY

Currently there are approximately 430 storage fields in the United States and another 28 in Canada. The geographic spread of these storage fields are shown in Figure 3-9. There are numerous ways to describe this capacity, with the most common measures being working gas capacity and maximum deliverability.[30] In addition, there is a significant range in the capabilities of these fields, as some are very small and others are part of large complexes, such as Leidy, Pennsylvania and Dawn, Ontario.[31] Furthermore, as a result of geology, U.S. storage fields are fairly concentrated. For example, storage facilities in the states of Pennsylvania, Ohio and West Virginia account for about 24 percent of the total working capacity, whereas Michigan and Illinois, in the Midwest, account for approximately another 23 percent and in the Gulf and southwest production area, Texas, Louisiana and Oklahoma account for approximately an additional 22 percent. These eight states plus California (*i.e.*, about six percent) account for about 75 percent of the U.S. working capacity for storage with the remaining 25 percent spread out over 22 other states. 21 states currently have no natural gas storage capability.

Lastly, for the purposes of the Energy Information Administration's (EIA) widely tracked weekly gas storage report, storage capacity is divided into three regions, namely the East region (27 states), West region (13 states) and the Producing region (eight states). These regions are identified further in a map contained in Appendix D.

FIGURE 3-9: US AND CANADA NATURAL GAS STORAGE FACILITIES



---

[30] These and related storage terms are defined in the Appendix B.

[31] The Leidy complex has 61 BCF of working gas and a maximum delivery capability of 1,224 MMCFD, whereas the Fair storage field in Pennsylvania has only 17 MMCF of working gas and a maximum deliverability of 1 MMCFD.

Chapter 4—Natural Gas Demand

This chapter provides a brief overview of U.S. natural gas consumption. Each of the four sectors (*i.e.*, residential, commercial, industrial and electric) of natural gas demand is discussed, with the primary focus being on the electric sector. Also, included is the possibility of a fifth sector, namely the transportation sector, emerging as a significant contributor to overall U.S. gas demand, although this likely will require a legislative initiative.

In each of the discussions of the various sectors, the primary determinants for demand are highlighted, along with the overall potential for long-term gas demand growth within the sector. For the industrial sector one of these determinants is the price elasticity effect that occurred during the past decade, which caused demand within the sector to permanently decline (e.g. demand destruction). In the case of the electric sector, which is by far the primary growth sector, the discussion is expanded to highlight the major demand attributes, such as fuel switching, fuel displacement, changes in power plant technology and sensitivity to the severity of summer weather.

The concluding sections review the overall seasonality of U.S. gas demand and provide an outlook for the future growth of this fossil fuel. The latter section focuses primarily on three scenarios for the gas-fired plants within the electric sector that focus on most of the key issues currently being addressed by the power industry (*e.g.*, CO_2 legislation, coal retirements, new nuclear capacity, renewable portfolio standards and others).

According to the Energy Information Administration's (EIA) 2011 Annual Energy Outlook (AEO), natural gas supply has increased 480 trillion cubic feet (TCF) since the AEO 2010.[32] Looking forward, EIA expects 45 percent more shale gas production and 20 percent overall gas production for the Lower 48 states by 2035. This increased supply has led to lower cost natural gas thereby supporting its role as an important fuel for electric generation and its part in electric system reliability going forward.

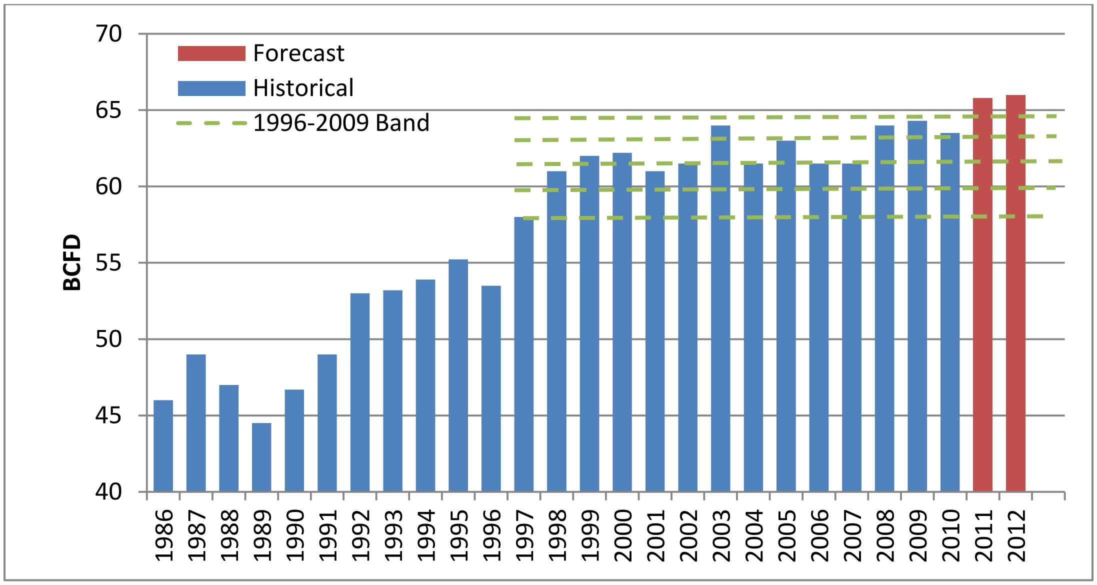
Historical Perspective and Short-Term Trends

Figure 4-1 summarizes the historical trends for total U.S. natural gas consumption over most of the last three decades and includes a near-term projection for additional perspective. While the growth in natural gas consumption from 1986 to 1996 is unmistakable (*i.e.*, 3.4 percent per annum),[33] for the last 14 years U.S. natural gas demand has remained within a relatively tight range and, in effect, did not increase at all. While almost all of the annual variances during this time period were due to changes in the weather, particularly the winter weather, there were offsetting variances among the sectors with the most significant being the post-2000 decline in industrial sector demand being offset by increases in the electric sector (as discussed below). This basic trend for total consumption was broken in 2010,

[32] http://www.eia.gov/forecasts/aeo/source_natural_gas.cfm
[33] Fuel Use Act, which prohibited new electric utility gas-fired generators, but not new non-utility gas-fired plants, ended in 1987.

which represents the first significant increase in overall U.S. gas consumption in 15 years. Furthermore, additional growth is projected by most forecasters for both 2011 and 2012.

FIGURE 4-1: U.S. NATURAL GAS CONSUMPTION



Source: EIA and EVA.

While this may be the start of a new trend for the industry, the increase in consumption in 2010 is due primarily to the additional gas demand from coal-to-gas fuel displacement and by the economic dispatch schedules set by electric system operators—all attributable to low gas prices.[34] This is particularly true when 2008 demand levels are compared to those for 2010. The same observation exists for the additional growth projected for 2011, as projected incremental coal-to-gas fuel displacement accounts for about 65 percent of the net increase in demand.[35] Since coal-to-gas fuel displacement is a temporary phenomenon, due to fuel price fluctuations, the forecasted increases in gas demand for 2011 are likely temporary for the intermediate-term and may not be increasing, and just above the 14 year relatively narrow range noted in Figure 4-1. With respect to 2012, if the assumed impact of coal-to-gas fuel displacement in that year were to be eliminated, 2012 gas demand would be only slightly above the 14 year band noted in Figure 4-1. While long term natural gas demand is projected to grow, primarily as a result of the electric sector,[36] material growth in the intermediate-term as a result of non-temporary factors may not occur.

ANALYSIS BY SECTOR

At present there are four major sectors for primary natural gas consumption, with the still evolving transportation sector representing less than 0.1 percent of primary demand. Additive to primary demand is the fuel consumed by processing plants and pipelines to process and transport natural gas

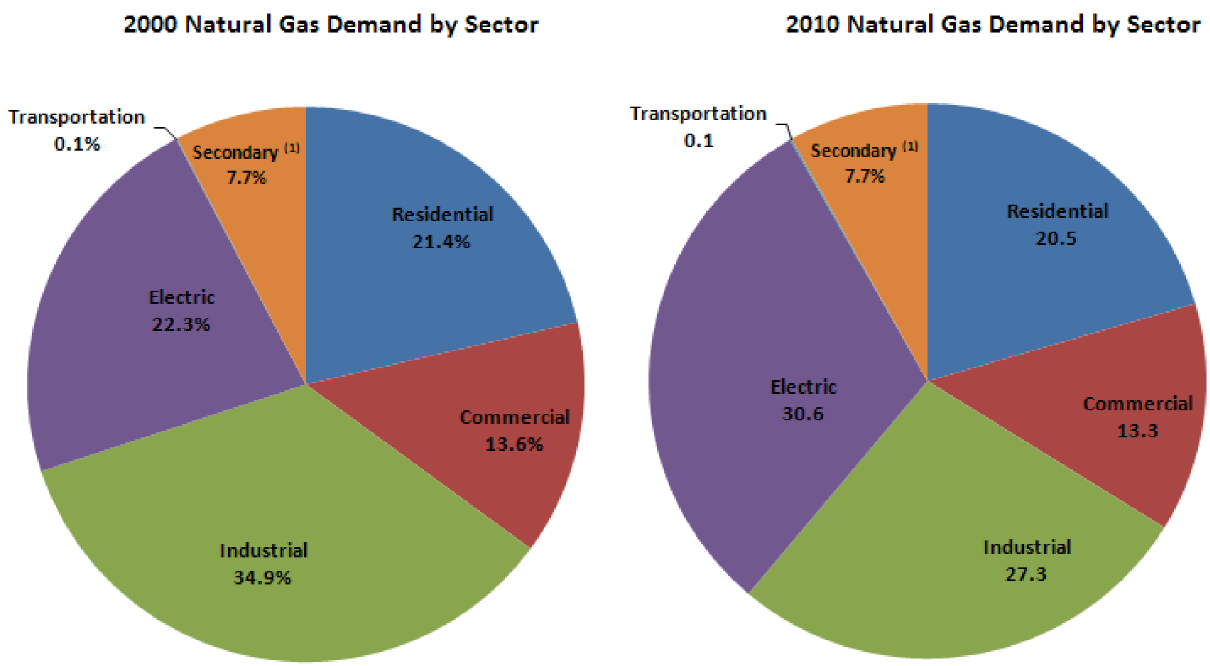
[34] Displacement refers to the change in consumption of one fuel to another—not necessarily a change in capacity.
[35] Anaylsis performed by Energy Ventures Analysis, Inc.
[36] The long-term outlook for natural gas demand is presented in the following sections of this chapter.

from supply sources to market areas, as well as distribution losses from LDCs within their service territories. As illustrated in Figure 4-2, the electric sector is the largest sector (*i.e.*, percent of primary), followed by the industrial, residential and commercial sectors in that order. The key attributes of each of these sectors is discussed in the material below.

RESIDENTIAL AND COMMERCIAL SECTORS

The residential and commercial sectors[37] represent about 34 percent of total gas demand and share three key attributes, namely (1) their consumption of gas is concentrated in the winter season; (2) there can be considerable variability in their winter consumption levels and (3) the outlook for future demand growth is for a very small rate of growth.

FIGURE 4-2: NATURAL GAS DEMAND BY SECTOR



1. Secondary Demand includes Lease and Plant Fuel, and Pipeline Fuel

Source: EIA

Winter

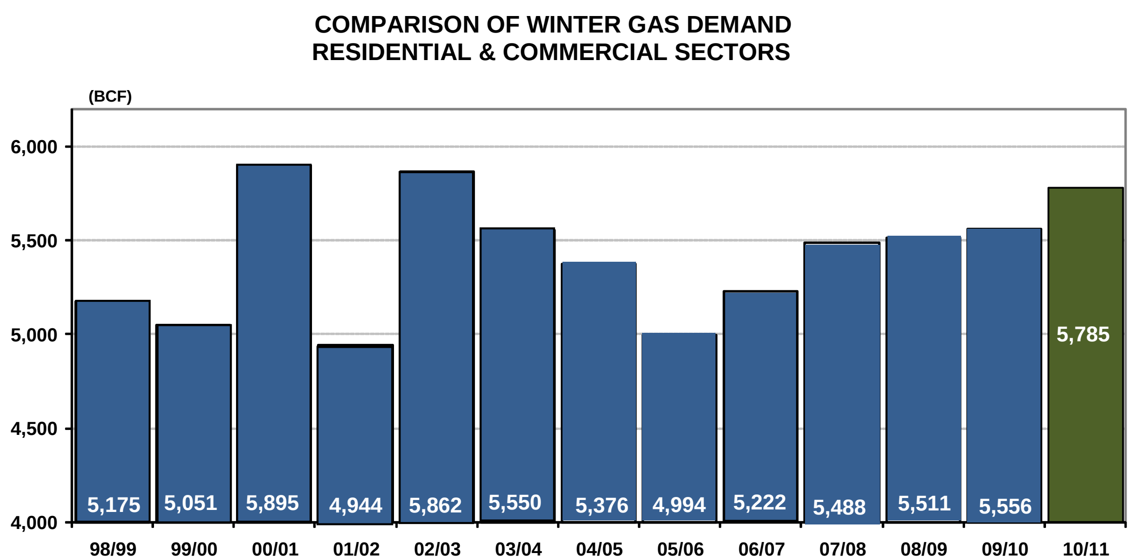
The majority of the gas demand for both the residential and commercial sectors is concentrated in the winter period. For example, average winter demand for the residential sector typically represents 70 to 75 percent of total annual consumption, while the equivalent metric for the commercial sector is 61 to

[37] Unlike the residential sector, which is very homogenous as gas consumption within this sector is confined to residential homes and apartment buildings, the commercial sector is very heterogeneous. Gas demand within the commercial sector is approximately as follows: office buildings (14 percent), educational facilities (14 percent), health care facilities (13 percent), lodging, such as hotel and motels (11 percent), as well as smaller percentages for (1) warehouse and storage, (2) public assembly buildings, (3) religious worship facilities, (4) non-mall retail (*e.g.*, strip shopping centers); (5) wholesale food sales establishments; and (6) public safety faculties.

66 percent. This occurs because within the residential sector space heating and water heating are the two largest uses of residential gas, as they account for approximately 59 and 28 percent of total residential consumption, respectively. For the commercial sector, space heating accounts for about 68 percent of total consumption.

In addition, there can be tremendous variability in the winter demand for the two sectors because of differences in the severity of the winter weather. Figure 4-3 compares and contrasts the winter demand (*i.e.*, November through March) for these two sectors over the last dozen years. As illustrated, winter gas demand for consecutive years has varied as much as 950 BCF, or 16 percent, which over the 151 days of winter equates to a change of 6.3 BCFD in gas demand. The fluctuations can also be seen in the number of Heating Degree Days (HDD) realized when compared to normal.[38]

FIGURE 4-3: COMPARISONS OF WINTER GAS DEMAND RESIDENTIAL AND COMMERCIAL SECTORS



HDDs	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12
vs Norm	-7.0%	-11.4%	9.5%	-11.1%	3.8%	-1.8%	-2.3%	-5.7%	-5.7%	0.5%	2.0%	2.0%	2.7%	1.3%

Source: EIA and EVA.

The combination of the concentration of total demand for the two sectors in the winter season and the potential variability in winter gas demand are the dominant reasons that the gas industry has developed significant amounts of market area storage.[39]

Outlook for Growth

For a variety of reasons the prospects for demand growth in either sector is minimal. With respect to long-term residential gas demand there are two offsetting factors, namely customer growth within the sector and intensity of use. With respect to the former, while the number of residential customers

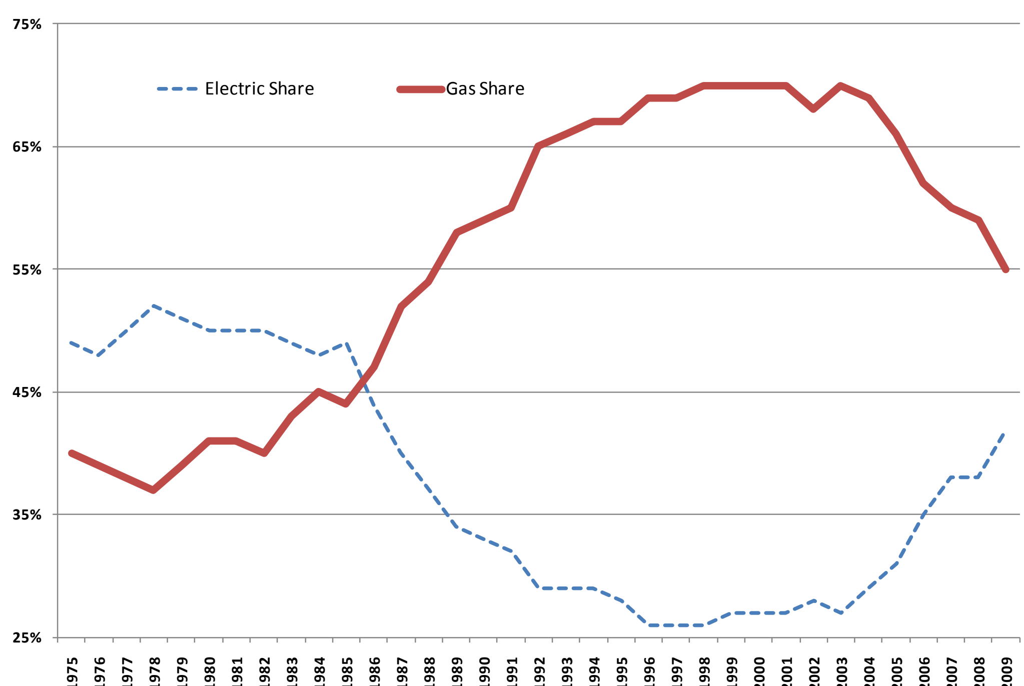
[38] National normal levels are accumulated by NOAA: http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/ddayexp.shtml

[39] See Appendices A for a discussion of key winters that have helped shape the structure of the current gas industry.

continues to grow, the rate of growth has declined for most of the last decade, with 2005 being the sole exception. This decline in the new customer growth rate primarily is due to two factors, namely (1) a reduction in the market share for houses using natural gas and (2) more recently, the impact of the recent economic recession on new housing completions. As illustrated in Figure 4-4 with respect to the gas sector's market share, while the gas industry is still capturing over 50 percent of new residences, this market share has been declining steadily since about 2003.

The offsetting factor to increased customer growth has been a decrease in the intensity of the use of gas within the average home. At present, gas consumption per customer is near an all-time low, as on a weather-adjusted basis, residential consumption per customer has declined in 16 out of the past 19 years (*i.e.*, from 95 to 74 MCF per customer, or about 22 percent). There are a series of factors behind this decline, which includes (1) higher energy efficiency in space heating equipment, (2) the turnover of U.S. housing stock with more energy efficiency equipment, (3) population migration to warmer winter climates, (4) the elasticity of demand effects due to the high gas prices that existed in the prior decade and (5) increase in insulation and weatherization as a result of high gas prices post Katrina and Rita. The latter tends to result in more behavioral conservation rather than structural conservation. By far the most significant of these factors is the higher energy efficiency in space heating equipment, which has occurred primarily as a result of governmental regulations on new appliances. This factor accounts for over half of the decline in the intensity of use per customer. With respect to behavioral conservation (*e.g.*, setting the thermostat lower and wearing a sweater) that occurred as a result of the recent high natural gas prices (*e.g.*, 2008), these austere practices appear to be continuing even though gas prices have declined—largely due to the recent economic recession impacting the residential sector.

FIGURE 4-4: MARKET SHARE FOR GAS OF NEW HOUSING COMPLETION



With respect to the commercial sector, gas demand is much more diversified than the residential sector.[40] As a result, it is more difficult to succinctly summarize changes in gas demand for this sector. While the commercial sector is affected by economic growth and was impaired, to a degree, by the recent economic recession, to date the sector has been slow to rebound and this trend likely will continue. Furthermore, growth in the sector since 1998 has only been 0.6 percent per annum and this is likely overstated because 2010 was a cold year. If 2010 is compared to other peak periods for commercial sector gas consumption, then results to date are still below 1997.

At present the long-term outlook for the residential sector ranges from 0.0 to 0.2 percent per annum in most forecasts, while commercial sector long-term growth rates range from about 0.4 to 0.6 percent per annum.

INDUSTRIAL SECTOR

Key Historical Event

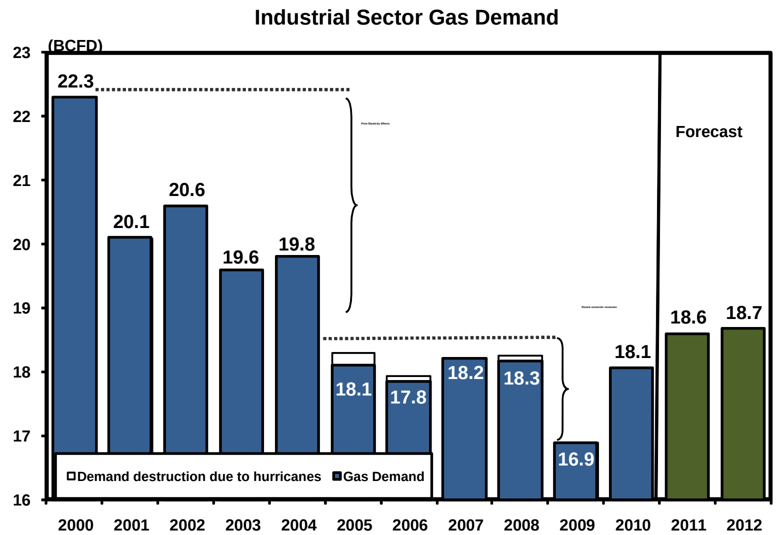
The most significant attribute for industrial sector gas demand over the last dozen years has been the 18 percent, or about 4.0 BCFD, decline in consumption because of the sharp increase in gas prices during the prior decade. Basically, the industrial sector absorbed almost the entire price elasticity effect from the increase in gas prices in the prior decade, as the price elasticity impact for the other sectors was relatively marginal.

In very simplified terms industrial facilities that had a rather large part of their cost structure linked to natural gas prices, such as ammonia and petrochemical plants, shut down, with most of the associated production, in essence, being transferred to overseas plants. Figure 4-5 graphically illustrates this phenomenal change in industrial gas demand.

With respect to the intermediate-term perspective for industrial sector gas demand, even though gas prices have declined in the current decade the rebound in industrial sector gas demand has been very modest, as the industry has not yet fully rebounded—if it ever will. Admittedly, the recent recession has impeded any effort by the industrial sector to restore previously shuttered U.S. capacity for natural gas feedstock (gas-intense) facilities. As a point of perspective, for the 12 months preceding the start of the recent economic recession, the industrial sector had increased demand to 18.6 BCFD. As noted in Figure 4-5, it likely will not be until next year before this figure is exceeded and even then marginally. The net result is that there likely has been close to a permanent 3.5 BCFD decline in industrial sector gas demand as a result of the natural gas price shocks that occurred in the prior decade.

[40] There also is a significant diversity in the average consumption for the various components of the commercial sector. For example, food service facilities on average use 141 cubic feet of gas per square foot of floor space (CF/F), whereas office building average 32 CF/F. In between are healthcare facilities at 93 CF/F and educational sites at 37 CF/F, with the composite average for all commercial buildings being about 42 CF/F.

FIGURE 4-5: INDUSTRIAL SECTOR GAS DEMAND



Key Components of The Sector

Six key energy-intensive industries account for about 82 percent of industrial sector gas demand. These six key industries are identified in Figure 4-6, while Figure 4-7 provides additional detail on the composition of gas demand for three of the largest energy intensive industries.

FIGURE 4-6: SIX KEY ENERGY INTENSIVE INDUSTRIES

Industry	Approximate Percent of Industrial Sector Gas Demand
Chemicals	29%
Petroleum and Coal	14%
Primary Metals	11%
Food	11%
Non-Metallic Minerals	9%
Paper and Products	8%
Other	18%

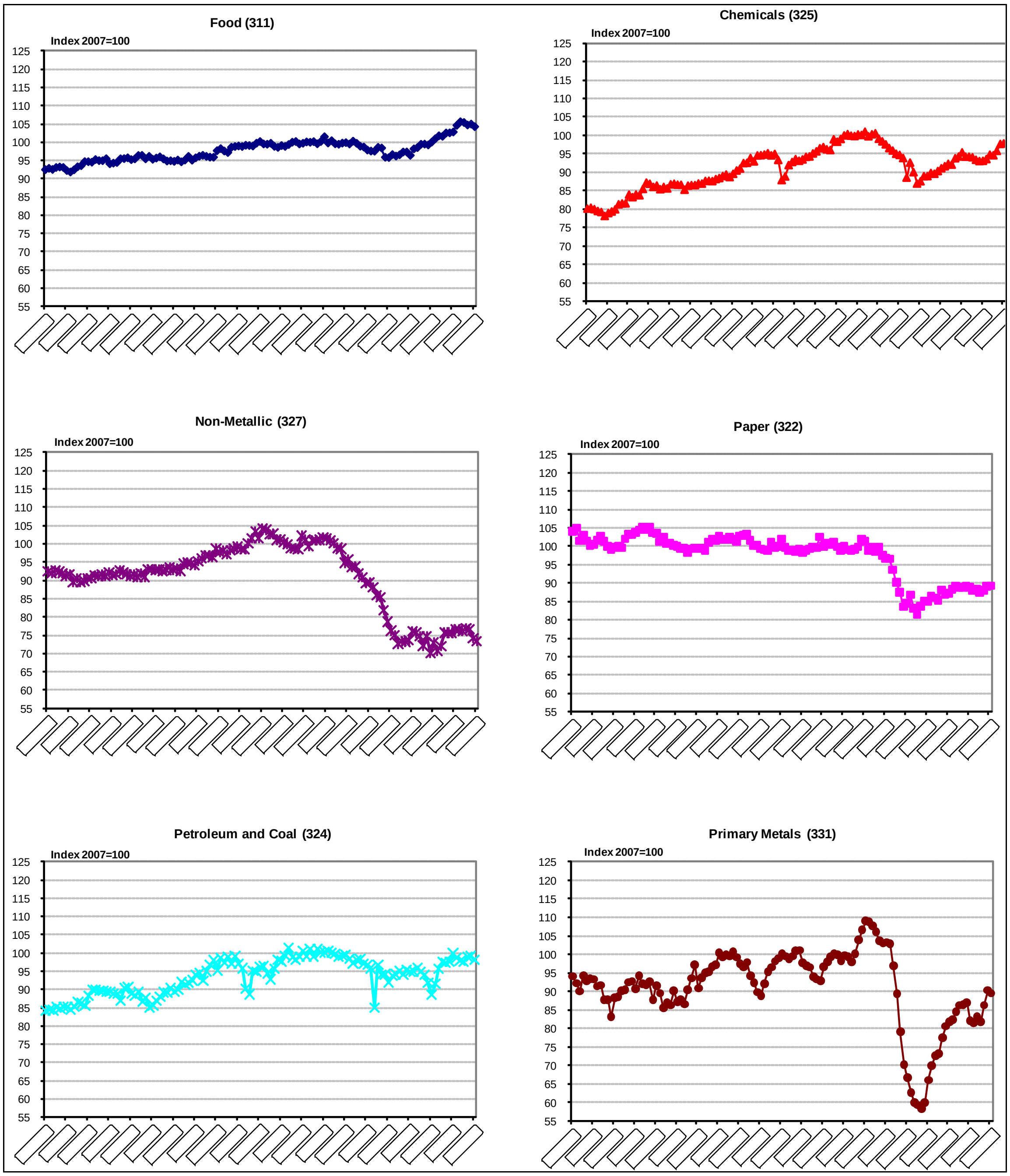
FIGURE 4-7: SOURCES OF U.S. INDUSTRIAL GAS DEMAND IN THE TOP THREE SECTORS

Total Industrial NG Demand For Six Key Industries = 5,744 BCF					
		Fuel	%Total	Nonfuel	%Total
		5,357	93%	398	7%
Chemical Industry-325 **Total = 1,697 BCF = 29%**					
	NG Demand	**Fuel**	**%Total**	**Nonfuel**	**%Total**
		1,355	80%	342	20%
	BCF		**% of Fuel**		**% of Nonfuel**
Other basic organic chemicals	370		22%		21%
Plastic materials and resins	335		24%		3%
Plastics & rubbers	135		9%		3%
Nitrogenous fertilizers	113		8%		50%
Petrochemicals	107		8%		no data
Alkalies & Chlorine	103		8%		no data
Ethyl alcohol	82		6%		1%
Industrial gases	60		1%		14%
Subtotal			**86%**		**92%**
Petroleum & Coal-324 **NG Demand = 825 BCF = 14%**					
	NG Demand	**Fuel**	**%Total**	**Nonfuel**	**%Total**
		825	100%	0	0%
	BCF		**% of Fuel**		**% of Nonfuel**
Petroleum refineries	766		93%		0%
Petroleum & coal products	3		0.4%		0%
Subtotal			**93%**		**0%**
Primary Metals-331 **Total Demand = 609 BCF = 14%**					
	NG Demand	**Fuel**	**%Total**	**Nonfuel**	**%Total**
		568	93%	42	7%
	BCF		**% of Fuel**		**% of Nonfuel**
Iron & steel	317		56%		76%
Alumina & aluminum	113		20%		21%
Foundries	70		12%		
Nonferrous metals, except alumn.	42		7%		
Refabricated steel	25		4%		
Subtotal			**100%**		**98%**

Source: EIA MECS 2006, revised October 2009

Further insights for the history of these six key energy-intensive industries are provided in Figure 4-8, which summarizes the trend for the production indices for each industry. As illustrated, each of these industries was impacted by the recent economic recession, with the greatest impact occurring for (1) non-metallic minerals, (2) primary metals, (3) paper and products and (4) chemicals.

FIGURE 4-8: INDUSTRIAL PRODUCTION INDICES FOR KEY ENERGY-INTENSIVE INDUSTRIES



Also, while there has been significant recovery from the recent economic recession, it will be some time before production, and as a result gas demand, recovers for three of these key industries (*i.e.*, non-metallic minerals, primary metals and paper and products).

Outlook for Growth

The primary driver for industrial sector gas demand is economic growth, which should cause gas demand within the sector to increase over the long-term. Offsetting this upward movement is (1) continued conservation within the sector, as capital investments are used to lower energy costs, and (2) at least historically the price elasticity effect in the event of an increase in gas prices. Concerning the latter, it should be a minor factor, as the outlook for gas prices based upon the current NYMEX futures and several forecasts are for relatively modest, forward gas prices.

More specifically growth is expected in the chemical industry, as U.S. chemical exports within foreign markets and U.S. produced fertilizer production rebound, again as a result of relatively modest domestic gas prices. With respect to increases in industrial gas demand as a result of further increases in ethanol production, this seems remote. While historically increases in ethanol production have been dramatic, these increases appear to be leveling off because of (1) a decline in margins within the industry; (2) an increased focus on the subsidies provided to ethanol production;[41] and (3) $7.00 per bushel corn prices,[42] which are, in a large part, attributable to increases in ethanol production.

At present the long-term outlook for the industrial sector ranges from 0.0 to 0.9 percent per annum.

ELECTRIC SECTOR

With respect to the electric sector for natural gas consumption, the following are the significant characteristics for the sector:

- **Growth:** Historically the electric sector has been the growth sector for natural gas demand and this trend likely will continue into the future.
- **Technology:** During the 1990s the electric sector went through a significant change in gas-fired power technology, as the new generation or more efficient combined cycle technology displaced the existing, older generation and less efficient oil and gas-fired steam generator technology. Absent the physical growth in gas-fired generation that occurred during the decade, the adoption of the newer technology actually decreased gas demand within the sector.

[41] According to the Congressional Budget Office (CBO):

- Producers of ethanol made from corn receive 73 cents to provide the biofuel equivalent to the energy in one gallon of gasoline, with $1.62 received by cellulosic ethanol producers and $1.08 by biodiesel producers.
- The cost of reducing gasoline consumption by one gallon costs U.S. taxpayers $1.78 for corn-based ethanol, $3.00 for cellulosic ethanol and $2.55 for biodiesel.
- The cost of reducing GHG emissions by one metric ton of CO_2 costs taxpayers $750 for ethanol, $275 for cellulosic ethanol and $300 for biodiesel.

See Congressional Budget Office, *Using biofuel tax credits to achieve energy and environmental policy goals*, July 2010.

[42] Corn production for ethanol accounts for about one-third of total corn production. In addition, prior to the surge in ethanol production corn prices were about $2.50 per bushel.

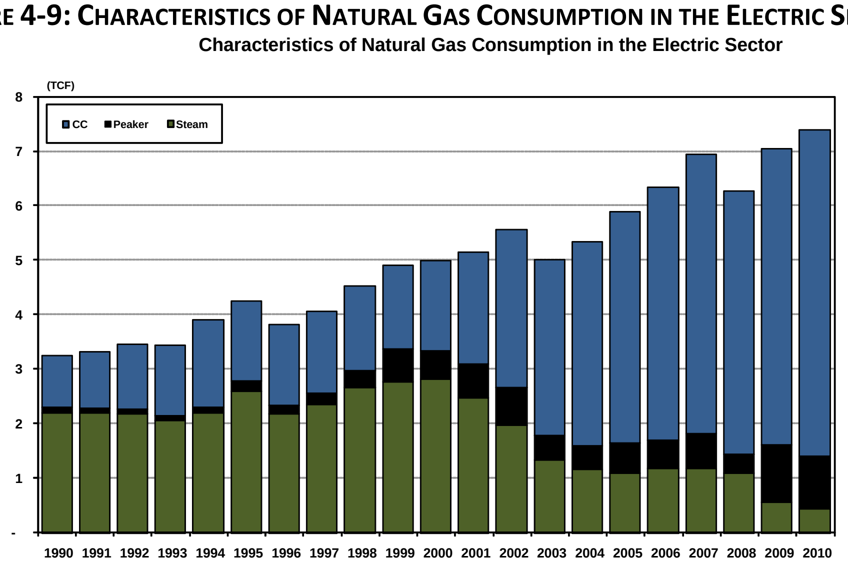
- **Fuel Displacement:** Since gas-fired generation historically has been at the margin in most regions, it has been subject to fuel displacement during periods when the relative prices for competing fossil fuels change significantly. Historically, the most common form of fuel displacement was from gas-to-oil; however because of fundamental changes in the relative price structure for oil and gas and environmental restrictions, it is highly unlikely that the industry will incur another episode of oil-to-gas fuel displacement in the future.
- **Summer Weather:** Since gas-fired generation is in general at the margin in most regions, it is very sensitive to increases in overall electricity demand during the summer season to accommodate increased air conditioning loads. As a result, near-term electric sector gas demand is very dependent upon the severity of the summer weather.

HISTORICAL GROWTH TRENDS

While natural gas consumption within the power sector was able to achieve substantial growth during the formative years of the industry,[43] during the 1970s and 1980s gas consumption within the sector declined (*i.e.*, about one percent per annum). The 1970s was the era of gas shortages, at least within the interstate market, while the 1980s were marked by the Fuel Use Act, which prohibited the use of gas in new utility generation plants until it was repealed in 1987.[44]

The combination of (1) the repeal of the Fuel Use Act; (2) the relatively low price of natural gas; and (3) the emergence of the very efficient combined cycle technology for gas-fired plants resulted in a surge in new gas plants during the next two decades, which in turn caused gas demand within the sector to once again start to grow (*i.e.*, 4.8 percent per annum in the 1990s and 3.5 percent per annum during the last decade). Figure 4-9 summarizes the growth in electric sector gas demand for the last two decades.

FIGURE 4-9: CHARACTERISTICS OF NATURAL GAS CONSUMPTION IN THE ELECTRIC SECTOR

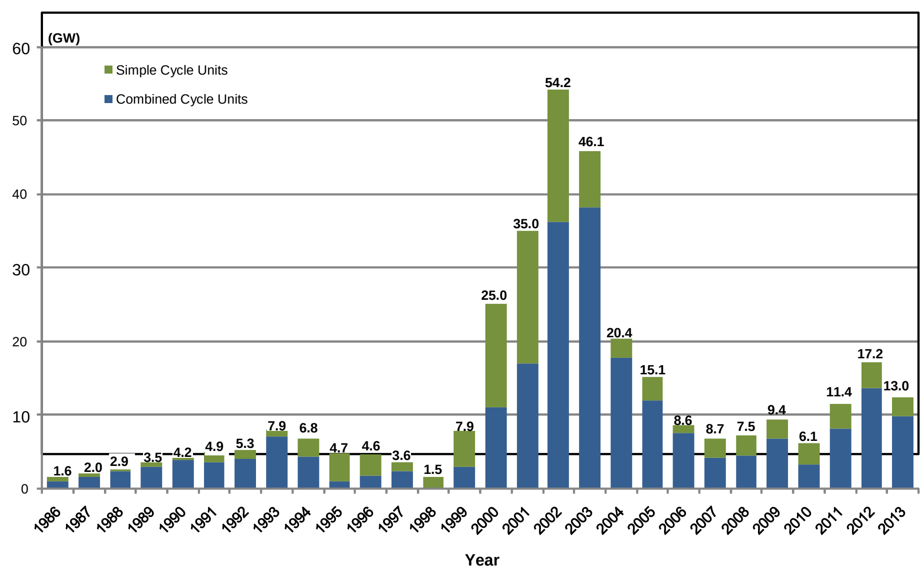


[43] In the 1950s and 1960s electric sector gas consumption grew at about 9.6 percent per annum. This high percentage growth was primarily because of a relatively small level of total consumption.
[44] Qualified non-utility generation using cogeneration facilities were allowed to build new gas-fired plants.

Technology

During the last two decades the power sector has gone through a significant change in the type of power plant technology that is used for gas-fired generation, namely the replacement of the oil and gas-fired steam generator by the more efficient combined cycle unit. Initially the emergence of the combined cycle unit occurred at a rather slow pace, as under the Fuel Use Act only qualified Non-Utility Generators (e.g. NUGs) could build new gas units. However, after the passage of the Energy Policy Act in 1992, which created the Exempt Wholesale Generator,[45] (e.g. EWG) the pace of building new gas-fired units began to pick up and started to reach record levels in 2000 and thereafter (*i.e.*, see Figure 4-10). State restructuring also played a significant role in building gas-fired generation.

FIGURE 4-10: ANNUAL ADDITIONS OF COMBINED CYCLE AND SIMPLE CYCLE GAS-FIRED CAPACITY



As a result of the Energy Policy Act of 1992, independent power producers (IPP) began to build new gas-fired power plants at an amazing pace. This period of entrepreneurial exuberance was unprecedented for the power industry and resulted in the building of approximately 125 GW of new combined cycle capacity and about 70 GW of new simple cycle peaking capacity in a period of five years.[46]

Fuel Displacement

Fuel displacement within the electric power sector occurs when the cost of one type of generation becomes less expensive than another type of generation, which results in the former displacing the latter and thus, overall increasing its percentage of the total load profile (in terms of energy). Since gas-

[45] Describing non-utility generators has become almost an art form unto itself. In the NGPA of 1978 the term qualified non-utility generator (NUG) was created. In addition, in 1988 FERC used the term independent power producer (IPP) to describe a non-qualifying, non-utility generator. Then in 1992 the Energy Policy Act created the term exempt wholesale generators (EWG). IPPs were included under the exempt wholesale generator category.

[46] The simple cycle and combined cycle units use the same basic aeroderviate turbine technology. The new simple cycle units were much more efficient than the existing peaking units.

fired generation is usually at the margin, at least historically, it is the type of generation that is most susceptible to fuel displacement.[47] Basically, there are two major types of fuel displacement, namely (1) switching between oil and gas-fired generation and (2) switching between coal and gas-fired generation. In addition, in the Northwest region there is a form of fuel displacement that occurs because of annual variations in hydro generation. During periods of low hydro generation gas-fired generation in the region increases, whereas the opposite occurs during periods of high hydro generation. It is common to refer to this as gas-to-hydro fuel displacement, although in this case the fuel displacement is not due to a change in the relative price of the two forms of generation.

Gas-to-Oil Fuel Displacement

Historically, the dominant form of fuel displacement has been oil-fired generation displacing gas-fired generation when oil prices decline sharply or alternatively when gas prices increase without a corresponding increase in oil prices. The start of this phenomenon of gas-to-oil fuel displacement began in 1986 when oil prices declined dramatically as a result of a lack of discipline within OPEC.[48] This is considered the grandfather of all gas-to-oil fuel displacement and was one of the largest gas-to-oil fuel displacement events in the history of the industry. While of short duration, there was another fuel displacement event in 1988, again due to a decline in oil prices.

During the 1990s there was a series of relatively small fuel events that occurred primarily as a result of increases in gas prices, which in turn were the result of severe weather events (*e.g.*, Hurricane Andrew in 1992 and March 1993 Blizzard). Also, during this period the capability to fuel switch was facilitated by a number of utilities converting their residual-fuel-fired boilers to dual-fuel capability (*i.e.*, oil and gas-fired).

While there were other fuel displacement events in 1996 and 1997, they were small compared to the increase in oil-fired generation that occurred in late 1998 and early 1999 because of the decline in oil prices to about $10 per barrel.

Starting with the winter of 1999/2000, which marked the end of the gas bubble and the beginning of the rise in gas prices, gas-to-oil fuel displacement became a rather common event as it occurred in every year between 2000 and 2005, with the highest levels of fuel displacement occurring during the winter of 2000/2001 and the winter of 2003/2004. Subsequently, global oil prices began to rise and by early 2006, gas-to-oil fuel displacement ceased to exist, with gas-fired generation dominating the market place, particularly with the combined cycle becoming entrenched within the industry.

Coal-To-Gas Fuel Displacement

Primarily as a result of the impact of the transitional shales, natural gas prices dropped dramatically in the latter part of 2008 and have stayed at relatively low levels since then. This has resulted in gas-fired

[47] On rare occasions there have been other forms of fuel displacement. For example, in the latter part of 1998, when oil prices declined to about $10 per barrel, residual-fuel displaced coal-fired generation in some regions.

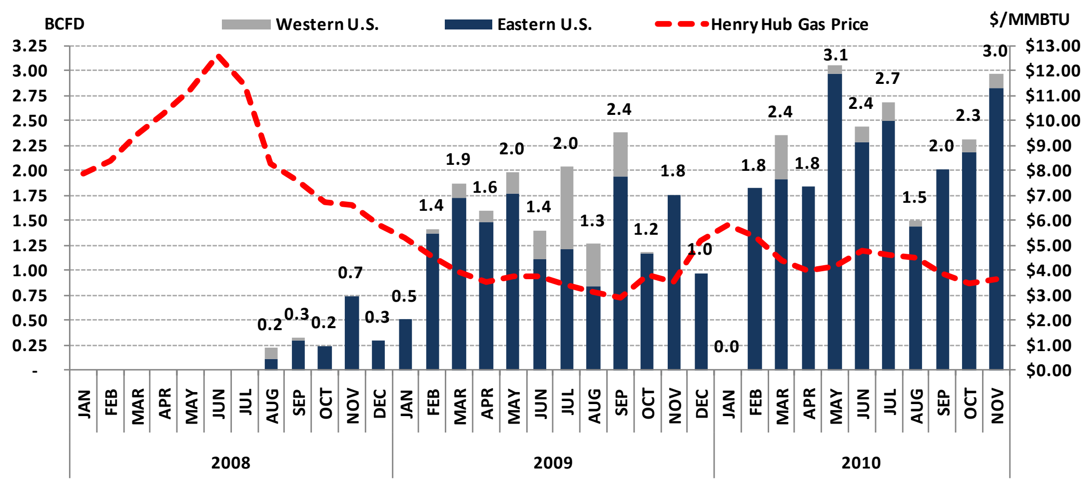
[48] Source EIA, OPEC members increased production and offered netback-pricing arrangements to maintain market share and to offset declining revenues. The failed price controls resulted in steep declines in petroleum prices in the United States: http://www.eia.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm

generation being less expensive than coal-fired generation in several regions and, as a result, caused the first sustained coal-to-gas fuel displacement event in the history of the industry. Prior to this event there were three relatively small coal-to-gas fuel displacement events, but each only lasted a few weeks.[49]

Figure 4-11 summarizes by month the increased gas demand within the power sector due to fuel displacement. For 2009 the annual average demand increase was 1.5 BCFD, whereas for 2010 it is estimated to be about 2.1 BCFD. As indicated in Figure 4-12, coal-to-gas fuel displacement, at least to date, has been primarily an Eastern phenomenon, as over 90 percent of the displacement of coal-fired generation has occurred east of the Mississippi River. Furthermore, within the Eastern U.S. this coal-to-gas fuel displacement is concentrated in the Southeast.

The current coal-to-gas fuel displacement event already has lasted for 29 months and based upon the current NYMEX futures for gas and coal prices it will last for at least another 48 months, if not 96 months.

FIGURE 4-11: ESTIMATED IMPACT OF COAL-TO-GAS FUEL DISPLACEMENT ON GAS CONSUMPTION—MONTHLY DISPLACEMENT BY NATURAL GAS



Summer Weather

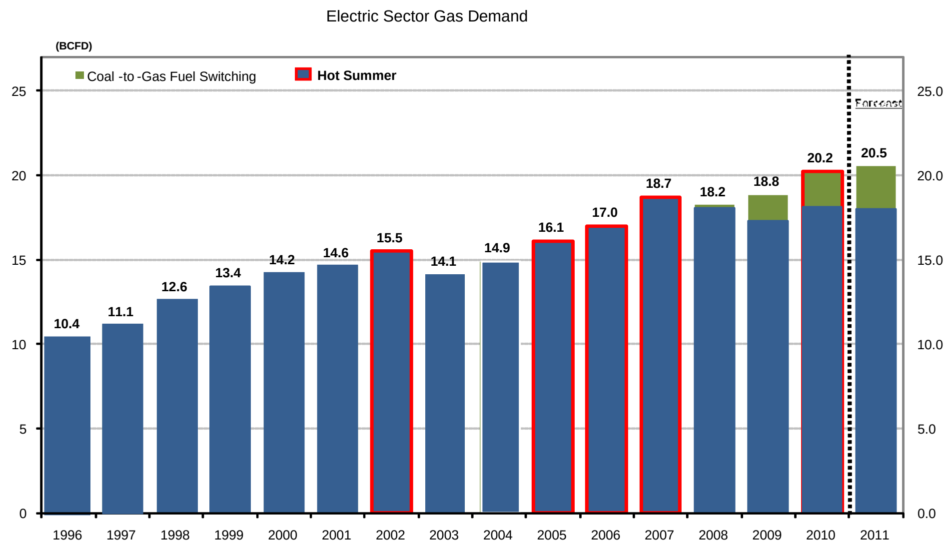
Near-term gas-fired generation, and as a result, power sector gas demand is very sensitive to the severity of the summer weather. This occurs primarily because gas-fired generation is at the margin and thus, absorbs most of the swing in overall electricity demand that occurs as a result of increased air conditioning loads. Figure 4-12 summarizes power sector gas demand over the last 15 years and highlights the five summers that have been particularly hot. As illustrated, this causes a near-term increase in power sector demand, which in most cases is followed by a decline in the subsequent year or years, as the summer returns to closer to normal conditions. This phenomenon often makes it difficult to use simple trend analysis to predict intermediate-term gas demand within the sector. Figure 4-13

[49] The three prior events were in February 1992, August/September 2004 and September/October 2006.

also illustrates the annual impact that coal-to-gas fuel displacement has had on recent gas demand for the power sector.

The impact of the summer weather on near-term power sector gas was particularly acute during the last summer, which was the hottest summer on record[50] and is even more evident when examining just the change in the summer season gas demand (*i.e.*, Figure 4-12 presented annual power sector gas demand). For example, as noted last summer was the hottest summer on record.

FIGURE 4-12: ELECTRIC SECTOR GAS DEMAND



TRANSPORTATION SECTOR

At present natural gas use within the transportation sector is almost *de minimus*, as it represents less than 0.2 percent of total natural gas consumption. This relatively small amount of gas demand (*i.e.*, on average 0.09 BCFD) is due to the use of natural gas in passenger cars and fleet vehicles. Despite legislative attempts to stimulate gas demand within the transportation sector, over the last 15 years the use of natural gas in transportation sector has increased only 29 BCF per year, as the natural gas fuel option has never been popular with drivers. The chief drawbacks appear to be (1) the lack of natural gas fueling stations; (2) the loss of most of the trunk space because of large natural gas fuel tanks; and (3) the higher initial vehicle cost. These factors offset the lower effective cost per gallon of fuel.

Going forward there are two potential areas for increased natural gas use within the transportation sector, namely (1) passenger vehicles and (2) large trucks used for long haul transportation. As discussed, any significant growth in the former seems remote, particularly with the increased mileage occurring for newer models using the internal combustion engine.[51] However, the possibility of natural gas use for tractor trailer vehicles is higher, particularly for that portion of long-haul truck transport that occurs along distinct corridors using the interstate highways. To date success in the use of natural gas in

[50] The weather for June through August 2010 was 18.3 percent warmer than normal based upon population weighted cooling degree days (CDD), whereas the same metric for 2009 and 2008 was 5.7 percent cooler and 2.2 percent warmer.

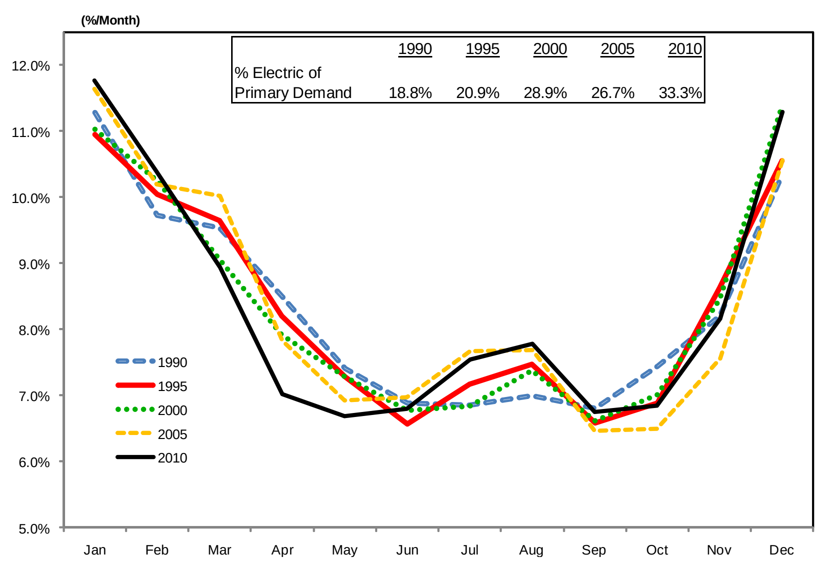
[51] "Conventional gas-powered cars starting to match hybrids in fuel efficiency", *Washington Post*, March 9, 2011.

large trucks has been limited. For example, the only significant use to date is the result of Long Beach, CA requiring that all trucks servicing the port of Long Beach (*i.e.*, one of the busiest ports in the nation) be fueled by natural gas. In addition, there have been discussions on the use of natural gas for tractor trailer vehicles transporting goods along the Los Angeles to Salt Lake City corridor. Legislation likely will be required to further advance the use of natural gas in tractor trailer vehicles (*i.e.*, the so-called Boone Pickens plan), as the cost to convert the engine is substantial.[52] While, in theory, the replacement of all the diesel fuel used in heavy duty vehicles by natural gas would equate to a 14 BCFD market, in reality, if legislation were enacted requiring the use of natural gas for these vehicles, the increase in natural gas consumption likely only would be in the 1.5 to 3.0 BCFD range. The reality reflected (1) the reluctance of operators to absorb the initial cost of converting their fleets of heavy duty vehicles; (2) the need to build new retail fuel pumping stations, and (3) the likelihood that only dedicated traffic along specific interstate corridors is a candidate for such a change.

SEASONALITY

As previously discussed, there is a strong seasonal characteristic to natural gas consumption, with winter consumption levels well above those for spring, summer and fall. This phenomenon is illustrated in Figure 4-13, for selected years over the last two decades. While heating load in the residential and commercial sectors still dominates the seasonal nature of natural gas demand, the steady growth of gas-fired generation within the electric sector has altered the profile with respect to the summer load profile, with the net result being the emergence over time of an increase in peak summer gas demand. This latter phenomenon is evident in Figure 4-13 when one compares the 1990 gas consumption profile with that for 2010. In 1990 peak summer gas consumption (*i.e.*, July through August) represented less than 14 percent of total annual gas consumption, whereas in 2010 this metric is approaching 15.5 percent. As noted in Figure 4-13, electric sector gas demand over the two decades has increased from about 19 percent to slightly over 33 percent.

FIGURE 4-13: SEASONALITY OF NATURAL GAS DEMAND



[52] One example of the potential for legislation is the House of Representatives proposed bill entitled NAT GAS Act of 2011.

Outlook For Growth

With the possible exception of the transportation sector,[53] almost all of the future growth in natural gas demand will come from the electric sector. However, there is a wide range of views on the potential growth for electric sector gas demand. This occurs because gas-fired generation tends to be at the margin, historically, and is impacted by the actions for all the other forms of electric power generation. Nonetheless, changes in the electric sector (*i.e.,* growth in gas demand, decrease in coal generation) will ultimately increase demand levels due to the base-load functions gas-fired generation is expected to provide.

In order to provide the reader with some perspective on the potential range for growth in electric sector gas demand, three scenarios that encompass varying views on the current factors impacting the electric power industry have been constructed.[54] These scenarios are summarized in Figure 4-14 and include alternative views concerning key policy issues, such as (1) future carbon control legislation and (2) requirements concerning renewable portfolio standards (RPS) and clean energy sources (CES), as well as (3) the overall growth of the economy and continuing improvement in energy efficiency rather than other sectors due to improvements in technology. Also, these scenarios examine the range of outlooks concerning, (4) the pace of retirements for the existing fleets of coal-fired plants (primarily due to pending environmental regulations) and (5) the possible construction of new nuclear plants (about 7 GW of new capacity over the next 10 years).[55] While there are other factors that could be included in these scenarios, the ones identified in Figure 4-14 are considered the major variables.

Figure 4-14: Power Sector Gas Demand Sensitivity Cases

	Low	Base	High
Carbon	None	2018(1)	Waxman-Markey
Economic Growth	2.0%/yr	2.5%/yr	3.0%/yr
RPS/CES	Obama 80% by 2030 (2)	400TWh by 2030	400TWh by 2030
Energy Efficiency Improvement	Residential 0.75% Commercial 0.75% Industrial 0.75%	Residential 0.5% Commercial 0.5% Industrial 0.75%	Residential 0.1% Commercial 0.1% Industrial 0.1%
Coal Retirements By 2030	30 GW	60.1 GW	100 GW
Nuclear By 2030	25,000 MW	20,780 MW	5,500 MW

(1) $20 per ton carbon tax with five percent real escalation.

(2) 80% of all energy from Clean Energy Sources (i.e., includes renewable, nuclear, coal with carbon sequestration and gas plants); however, gas plants get only a 50% credit.

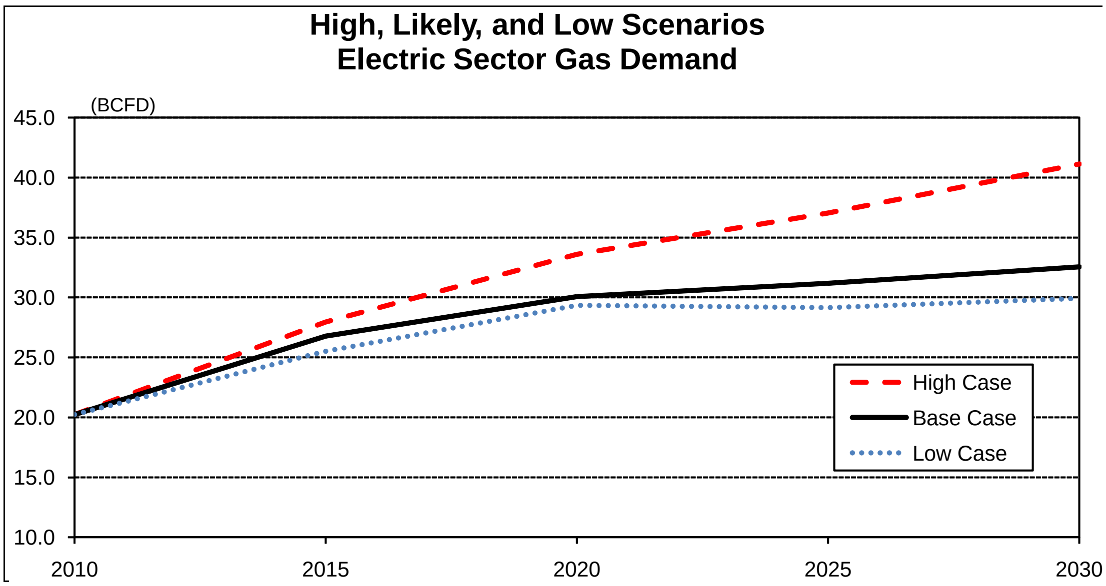
[53] As was discussed earlier in this chapter, the potential growth in the transportation sector could be on the order of 1.5 BCFD, however this likely would require a legislative initiative and none are currently under active consideration.

[54] This analysis was performed by Energy Ventures Analysis, Inc. for NERC.

[55] The low estimate for new nuclear capacity which would be part of the high growth case for electric sector gas demand, assuming planned nuclear uprates, as well as proceeding with three nuclear units that already are far along in the review process and have qualified for federal loan guarantees.
NERC 2011 Long-Term Reliability Assessment: http://www.nerc.com/files/2011%20LTRA_Final.pdf

The resulting gas-fired generation (*i.e.*, combined cycle, steam generator and peaking) is converted to natural gas demand. The results of the three scenarios for electric sector gas demand are summarized in Figure 4-15. As illustrated, while there is considerable upside for electric sector gas demand, depending upon the policies and regulations adopted by this country, there is little downside from the base case demand scenario.

FIGURE 4-15: SCENARIOS FOR ELECTRIC SECTOR GAS DEMAND



OBSERVATIONS

While natural gas consumption has been relatively flat for the last 15 years, gas demand within the electric sector has been growing, particularly since the repeal of the Fuel Use Act in 1987. For example, in 1990 annual electric sector gas consumption was 3.2 TCF per year, which equates to 8.9 BCFD, whereas last year annual consumption was 7.4 TCF, which equates to about 20.2 BCFD. This growth has caused the electric sector to become the largest of the four sectors for natural gas demand (*i.e.*, accounting for one-third of total demand), whereas in 1988 it was the smallest sector. During the last decade the increase in electric sector gas demand almost completely offset the decline in industrial sector gas demand.

Unique to the electric sector gas demand is that it can be impacted significantly by fuel displacement within the electric power industry, and that near-term demand can be affected significantly by the severity of the summer weather, whereas most of the rest of the consuming gas sectors are affected heavily by the severity of the winter weather.

Going forward, the electric sector likely will continue to account for most of the increase in natural gas consumption. The range of potential growth in electric sector gas demand over the next two decades is between 30 and 41 BCFD, which equates to about 2.0 to 3.6 percent per annum growth rate.

Chapter 5—Natural Gas Supply

There are four segments to the U.S. supply portfolio:

- **Domestic Production:** This is by far the dominant segment of the U.S. supply portfolio and likely will be dominated for the next two decades by the transitional shales.
- **Canadian Imports:** The contribution of this segment has been declining over the last five years and likely will continue to do such in the future, as conventional production from the Western Canadian Sedimentary Basin (WCSB) has become a marginal source of North American production.
- **LNG Imports:** While during the earlier part of the last decade there was considerable emphasis on U.S. LNG imports that resulted in the construction of approximately 22 BCFD of regasification capacity, U.S. LNG imports are no longer required, except to meet some specific regional and seasonal supply requirements.
- **Arctic Gas:** Even though there have been considerable delays, long-term the possibility of one or both of the two Arctic gas pipelines being built remains a distinct possibility.

Each of these segments of the U.S. supply portfolio are briefly described in the following material with the majority of the discussion on domestic production and the impact of the transitional shales.

BRIEF HISTORY

MAJOR MILESTONES

While it is beyond the scope of this report to review, in detail, the last 70 years of U.S. gas supply, there are some critical milestones, or events, that are worth briefly highlighting, as they have been critical in shaping today's supply industry. These key milestones are as follows:

- **Regulated Era:** As was discussed in Chapter 2, for most of the 1940s through the 1970s, almost every aspect of the U.S. gas industry was regulated, including key attributes of natural gas supply. During this period almost all gas supply was from conventional resources[56] and was, for the most part, associated production (*i.e.*, associated with oil supply), although there were exceptions such as the San Juan basin production. At the time most producers viewed the associated gas production as a by-product to the more important oil production.

[56] The terms (1) conventional and (2) unconventional gas do not lend themselves to rigorous definitions, particularly as the industry has changed over time. In general, conventional gas is thermogenic gas that originated in a source rock and then subsequently migrated through cracks and fissures to a layer of impermeable rock, where it exists in pools that are formed by structural traps. Importantly, conventional resources could be developed using conventional production techniques at the time. Unconventional resources consist of thermogenic gas that cannot migrate because it exists in very low permeability rock layers. In addition, in the past unconventional resources could not be developed economically using conventional production technology, but instead required unconventional production technology, such as horizontal wells and massive hydraulic fracturing. The latter techniques are now commonplace within the industry. As the industry has matured unconventional resources are merely defined as consisting of the following three categories of natural gas, if hydrates are excluded; tight sands (*i.e.*, less than 0.1 millidarcies), coal-bed methane and shales. Appendix D contains maps highlighting the various (a) shale plays, (b) tight sands plays and (c) the coal-bed methane plays.

- **Natural Gas Shortages**: Eventually these stringent regulations, which provided little incentive to drill for non-associated, or dry, gas resulted in the natural gas shortages that emerged in the mid-1970s (*i.e.*, see Chapter 2). Also, these regulations resulted in the sharp distinction between the interstate (*i.e.*, where the shortages occurred) and the intrastate (*i.e.*, which were well supplied) markets.

- **Natural Gas Policy Act (NGPA) Era:** The response to the natural gas shortages was the replacement of the Natural Gas Act (NGA) of 1938 with the Natural Gas Policy Act in 1978.[57] In addition to creating price incentives to develop new natural gas reserves and thus, increase production, the NGPA represented the genesis of two of the three forms of unconventional natural gas production. In the case of tight sands, high gas prices were set in order to incentivize the industry to develop this form of natural gas resource, while the Section 29 tax credit was initiated in order to incentivize producers to develop coal bed methane production.[58] However, overall the industry still was focused on primarily developing conventional gas resources.

- **Deregulated Era/Gas Bubble:** One of the results of the complete deregulation of the natural gas industry, which as discussed in Chapter 2 occurred over the 1984 to 1992 period, was the creation of the 'gas bubble'. This extended period of excess supply, which lasted throughout the 1990s, was caused primarily by the 'released gas' that emerged as a result of the deregulation of the pipeline segment of the industry and the subsequent unbundling of the industry. Another contributing factor to the length of this period of excess supply was the rapid development of coal-bed methane production, which received a tax credit (*i.e.*, not a tax deduction) that inflated over time, but averaged about $1.00 per MMBTU during the 1990s.[59]

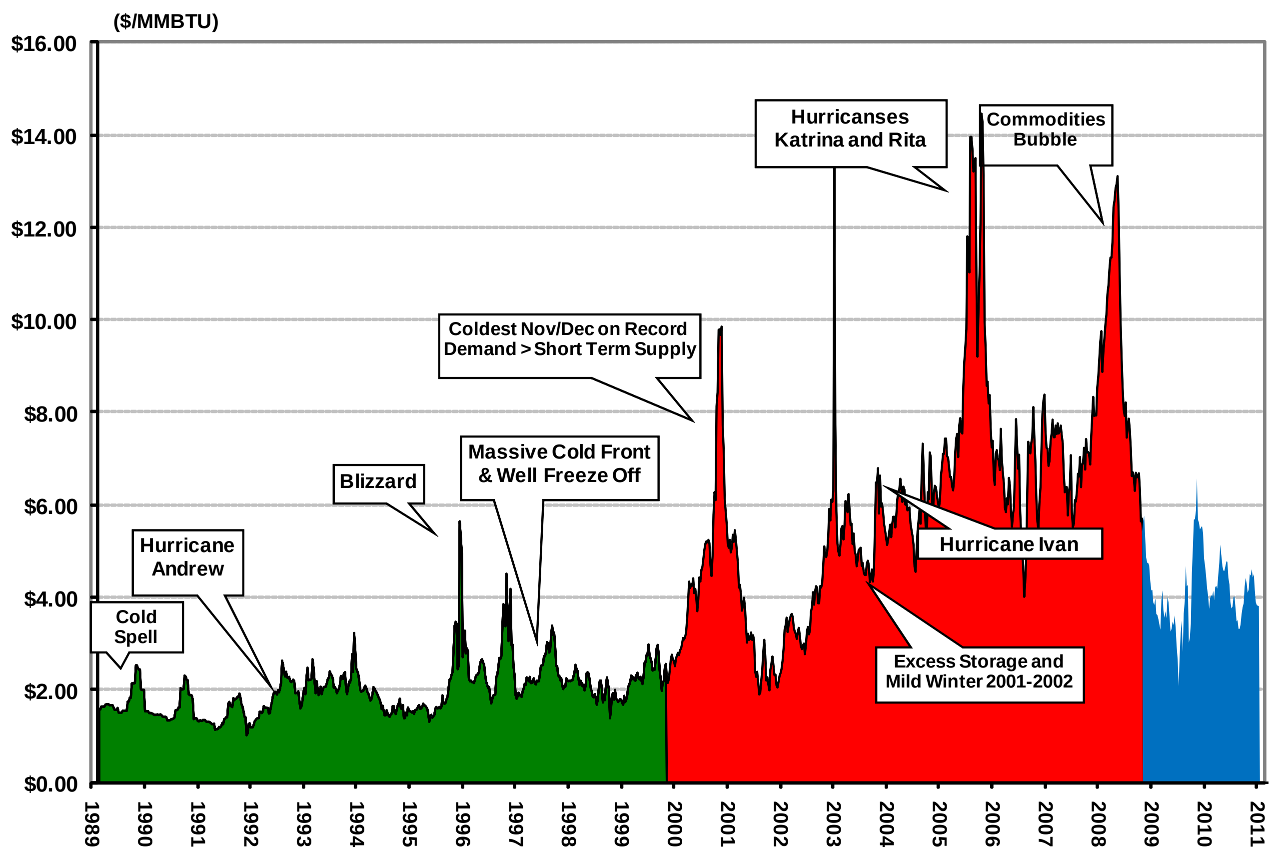
- **Era of High Gas Prices:** With the winter of 2000/2001 the 'gas bubble' came to an end, as the combination of demand increasing, natural declines of existing supplies and seasonal factors caused gas prices to soar to $8.00 to $9.00 per MMBTU (*i.e.*, monthly average gas prices) for two months during the winter, whereas average annual gas prices for the prior year were only $2.27 per MMBTU. While there was an exception, prices continued an upward trend for most of the rest of the decade, and finally peaked at about $13.00 per MMBTU (*i.e.*, a weekly average price) in mid-2008 (*i.e.*, see Figure 5-1). The primary focus during this period was on the development of new conventional resources, and to a lesser degree, tight sands and coal-bed methane (CBM) unconventional resources. This period was marked by the phenomenon of the exploration and production segment being on a 'treadmill'. The term embodies the concept that production from new conventional resources declined quickly and overall had short to mid-range production life.[60] This resulted in the industry constantly drilling to produce new production that barely met the decline in existing production, let alone any increase in demand.

[57] http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1978.html
[58] Technically the Section 29 tax credit was created by Congress in 1980.
[59] Coal-bed methane production increased from zero in 1986 to 3.7 BCFD by the end of the 1990s and currently is about 4.7 BCFD.
[60] The classic example of this phenomenon was the gravel-packed shallow water, offshore Gulf of Mexico wells for which production declined 50 percent in the first year and ceased to produce after the third year. Gravel packing is a drilling and completion technique used to accelerate production.

As a result, this became the exact opposite of the 'gas bubble' era, as it was a period of tight supply and high prices.

- **The Transitional Shales:** The era of tight gas supply and high gas prices came to an abrupt halt during the second half of 2008 when the industry began to appreciate the full impact of the transitional shales, which are the third component to unconventional resources (*i.e.*, see Figure 5-1).[61] The recent emergence of the shale plays can be traced back to Mitchell Energy and Development, which was acquired by Devon Energy in 2000. Mitchell Energy spent much of the 1980s and early 1990s trying different techniques to develop the Barnett shale (TX) and finally was able to develop its first production from the play in the early 1990s. Large-scale hydraulic fracturing, a process first developed in Texas in the 1950s, was first used in the Barnett in 1986; likewise, the first Barnett horizontal well was drilled in 1992.[62] While drilling and completion technology continues to advance, the latter, in essence, represents the major step in drilling technology that facilitated the rapid development of the shales.

FIGURE 5-1: HISTORICAL NATURAL GAS PRICES



Source: NGW and EVA, Inc.

[61] The recent economic recession, which started in the second half of 2008, also caused some decline in natural gas demand, although the major factor was the increase in supply from the emergence of the shales.
[62] U.S. Department of Energy: *Modern Share Gas Development in the United States, A Primer:* http://www.all-llc.com/publicdownloads/ShaleGasPrimer2009.pdf

While production from the Fayetteville (AR) and Woodford (OK) shales began to emerge during the middle part of the decade,[63] the next significant milestone in the recent emergence of the very prolific shales occurred in January 2008, when Range Resources and Chesapeake Energy announced to the industry the existence of the Marcellus (PA, WV and elsewhere in the Appalachian Basin) and Haynesville (LA and TX) shale plays. Then, in 2009 Petrohawk introduced the industry to the Eagle Ford (TX) shale play.

This, in combination with the evolving Horn River and complex Montney shale plays in Canada, represents the genesis of the transitional shale plays, that have reshaped the North American gas industry. As a point of reference shale production has increased from 1.5 BCFD in 2003 to 16.7 BCFD at year end 2010, which represents about a 15 BCFD increase, which is an unprecedented event in the history of the industry. At present shale production represents approximately 26 percent of total lower-48 production, whereas just eight years ago it represented only three percent. For the next two decades increases in shale production will dominate the industry.

WEATHER EVENTS

In addition to the above, there were a few significant weather events that have had an impact on the current structure of the industry. Probably the three most significant are noted below:

- **Winter of 1976/1977:** As was highlighted in Chapter 2, the severe winter of 1976/1977 exposed the shortages of natural gas supplies within the interstate market (*i.e.*, see Appendix A for a more complete assessment).

- **Winter of 1989/1990:** There was an extreme cold spell during the first part of the winter of 1989/1990, during which there were ice flows 12 miles out into the Gulf of Mexico. The loss of production due to well freeze-offs was substantial, which resulted in some pipelines not being able to meet demand. Furthermore, because of customers to the south increasing their supply takes, New York City was within 48 hours of not having enough supply. A number of changes occurred within the industry after this weather event, including pipelines installing control valves and revisions to tariffs to preclude customers from taking more than nominated gas supplies (*i.e.*, no more free no-notice service). It also resulted in the E&P segment taking greater precautions to preclude well freeze-offs. See Appendix A for a more complete discussion.

- **Hurricane Andrew (1992):** Hurricane Andrew exposed how vulnerable the deregulated U.S. gas industry was to the loss of production from the Gulf of Mexico, due to a major, unfortunate, hurricane that traveled through the gas well field within the Gulf of Mexico. The Gulf of Mexico at the time was the largest producing basin in the U.S. The industry substantially revamped operations after Hurricane Andrew. See Appendix A for a more complete discussion.

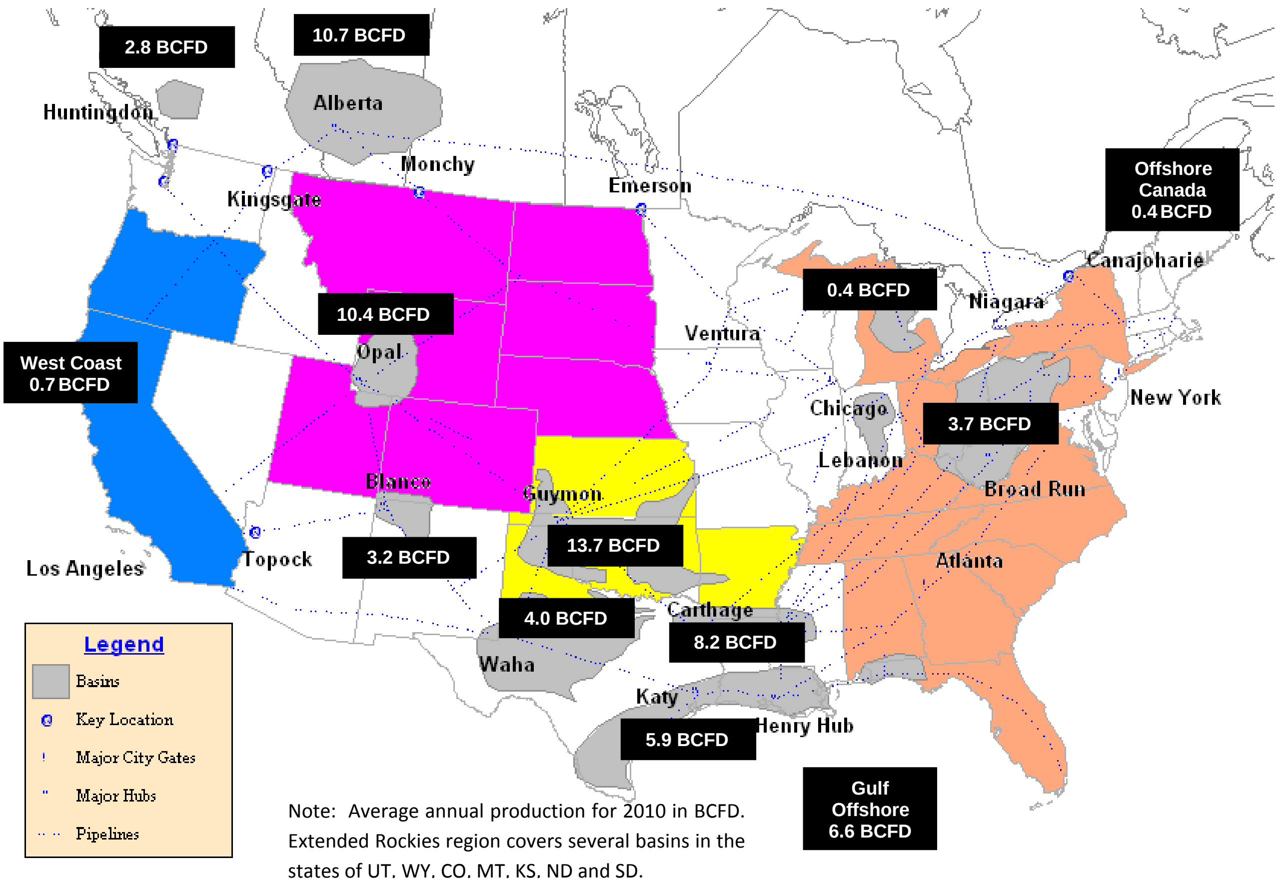
[63] First production from the Fayetteville shale play occurred in 2004, while Devon Energy drilled the first well for the Woodford shale play in 2005. The Fayetteville shale is recognized as one of the 10 largest gas fields in the U.S.

Domestic Production

Regional Overview

There are eight major producing regions within the U.S. which are highlighted in Figure 5-2, along with the three major producing areas for Canada.[64] The three highest U.S. producing regions, which are (1) the Gulf Coast (Onshore and Offshore) area, (2) the Mid-Continent and (3) the Rockies, represent about two-thirds of total U.S. production.

Figure 5-2: Major North American Production Areas



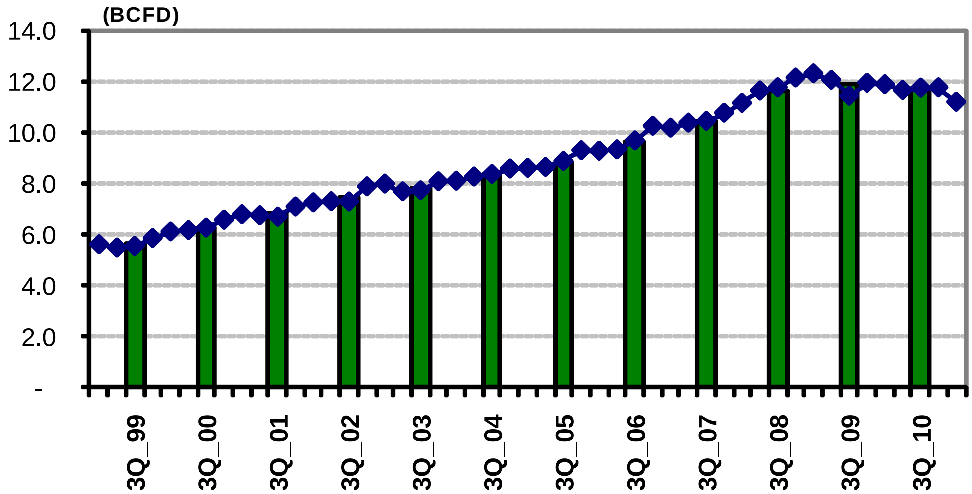
Each of these major producing regions has unique characteristics and a unique history, which are very briefly reviewed below. In addition, Appendix C presents production profiles for each major producing area which are similar to the profile for Rockies production presented in Figure 5-3.

- **The Rockies** covers large geographical area (*i.e.*, seven western states) that encompass at least 13 producing areas or basins. As a result, there is no simple description of this region, which encompasses, among other things, Powder River basin CBM production (*i.e.*, second highest CBM production in the nation) and the very economic Jonah field and Pinedale Anticline tight

[64] Subregions are highlighted for two of the major producing regions. More specifically, Michigan and the Appalachian basins are highlighted for the Eastern producing region, while Gulf Coast Onshore region is split into two subregions.

sands production. As illustrated in Figure 5-3, Rockies production was increasing significantly for the vast majority of the last decade and reach peaked levels of 12.4 BCFD.[65] However, since then Rockies production has leveled off and even incurred modest decline (*i.e.*, currently 10.4 BCFD), as drilling activity declined in response to declining gas prices at the end of the decade.

FIGURE 5-3: ROCKIES PRODUCTION



Note: Bars represent annual production levels (BDFD), while diamonds symbols represent quarterly production levels (TCF).

- **San Juan Basin:** There are two major types of production in the San Juan basin (NM and CO), namely (1) tight sands production which dates back to the 1930s and was the genesis for the El Paso pipeline and (2) coal-bed methane production. The latter represents the first significant response to the NGPA Section 29 tax credit and currently represents about 60 percent of the basin's total production. San Juan basin production has been in modest decline since about 2000.

- **Mid-Continent:**[66] Since 2002 Mid-Continent production has been increasing at a rather steady rate, primarily because of the emergence of the Barnett shale (TX). In addition, there has been significant contributions from the Fayetteville (AK) and Woodford (OK) shales. Over the eight year span production increased about 7.4 BCFD.

- **Permian Basin:**[67] This basin is largely an oil basin, with significant amounts of associated gas. However, the smaller New Mexico portion of the basin, along with parts of Texas Railroad District (TRDD) 8, are more gassy. Gas production in the basin has observed a saw tooth pattern, but since mid-2008 has been declining.

[65] All the figures noted in the discussion of the regions are wet production (*i.e.*, includes associated NGLs), whereas Exhibit 5-2 presents dry gas production data.
[66] This Mid-Continent region consists of KS, OK, AR and Texas Railroad Districts (TRDD) 7B, 9 and 10.
[67] The Permian basin consists of TRDD 7C, 8 and 8A plus four southwestern counties in New Mexico.

- **Gulf Coast Onshore:**[68] There is enormous diversity in the production along the Gulf Coast, as it is one of the largest producing regions in the nation. While conventional production in the region has been in a state of steady decline, this decline has been offset by a surge in production from the Haynesville (N. Louisiana and East Texas) and Eagle Ford (TRDD 1) shales. While for most of the decade Gulf Coast production was relatively flat, it has been increasing since 2009, because of the contribution from the shales.

- **Offshore Gulf of Mexico:** Offshore Gulf production, which consists of both shallow water production (*i.e.*, the shelf) and deepwater production (*i.e.*, greater than 1,000 feet of water), has been in a steady state of decline since about 2001. Furthermore, the rate of decline has been accelerated since the April 2010 BP oil spill. The latter has resulted in a de facto moratorium on most drilling in the Gulf. Some industry observers opine the offshore Gulf drilling will not return to near historical activity levels until 2012 or later.

- **Eastern Region:** While the Eastern region consists of almost all the states east of the Mississippi River, the two main producing areas are the Michigan and Appalachian basins. For decades the Eastern region was merely an afterthought for the U.S. E&P industry, as production was primarily controlled by small independents with individual wells being relatively small producers, although there were a lot of them. Production for most of the last decade was basically flat at about 2.9 BCFD. However, that all changed with the discovery of the Marcellus shale in 2008. Currently production is in excess of 5 BCFD and increasing at a very rapid rate.

- **West Coast Region:** This is the smallest of the producing regions and for all practical purposes represents the production within California. West Coast production has been in a slow state of decline since about 2001.

THE TRANSITIONAL SHALES

As noted earlier in this chapter, the outlook for U.S. production underwent a metamorphosis with the full emergence of the shale gas in 2008. In order to fully appreciate both the current and long-term impact of the transitional shales, the following are reviewed (1) the recent increase in shale production; (2) the major changes in drilling and completion technology that has accompanied the emergence of the shales; (3) the record setting increases in the U.S. resource base because of the shales; (4) their superior well economics; and (5) finally the long-term outlook for shale production.

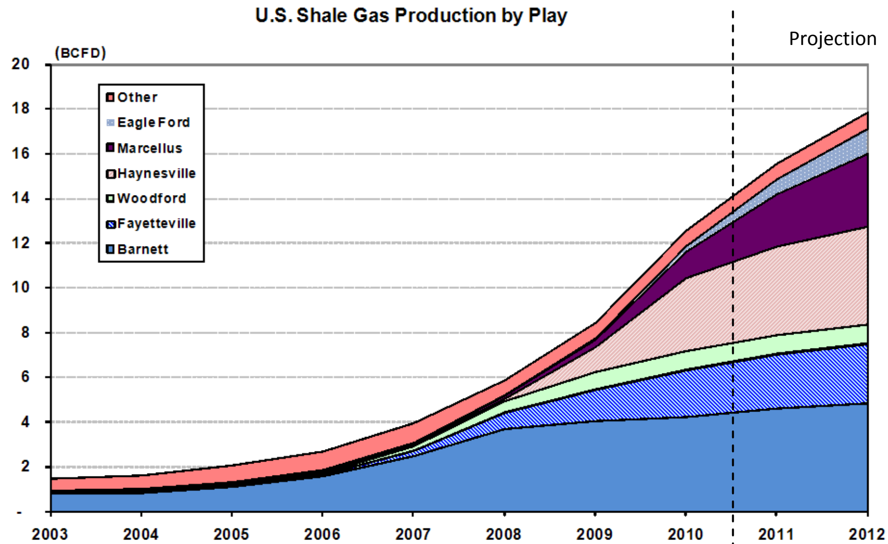
PRODUCTION

As illustrated in Figure 5-4, the growth in shale production since 2003 has significantly increased and represents something that has not previously occurred within the U.S. gas industry. As illustrated, average annual shale production since 2003 has increased from 1.5 BCFD to 14.5 BCFD, or approximately 13 BCFD, and is still growing with year-end 2010 shale production being approximately 16.7 BCFD.[69] The latter represents approximately 26 percent of total lower-48 production, whereas just

[68] The Gulf Coast Onshore region encompasses TRDD 1 through 6, plus Louisiana and Mississippi.
[69] Figure 5-4 includes both historical shale production and projections based upon current drilling activity for 2011 and 2012 that were taken from Lippman Consulting's Monthly Shale Production Forecast Model.

eight years ago shale production represented only three percent of lower-48 production. Year end production levels for the individual shale plays range from 0.5 BCFD for the newest of the major shale plays, namely the Eagle Ford shale, to 5.5 BCFD for the oldest of the major shale plays, namely the Barnett shale, with the very young Haynesville shale at 4.5 BCFD being a close second.

FIGURE 5-4: U.S. SHALE GAS PRODUCTION BY PLAY

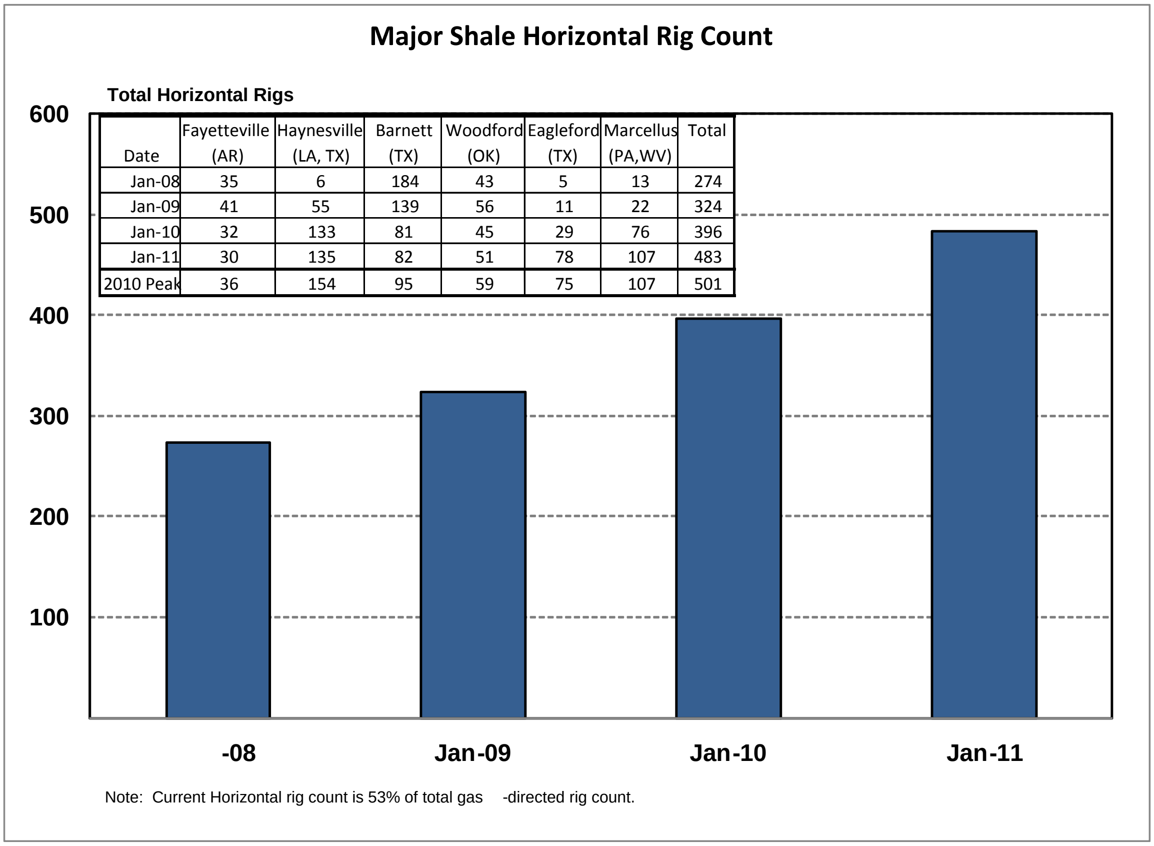


DRILLING ACTIVITY

The unprecedented growth in shale production over just the last few years is due to a combination of the prolific nature of the shale plays and the rapid increase in industry drilling activity for these plays, as they, for the most part, represent the best drilling well economics in the U.S. Figure 5-5 summarizes the increase in the horizontal rig count of the major shale plays over the recent past. While the horizontal drilling technique is by far the dominant method of developing these shale plays, there are some areas where vertical wells are drilled for these shale plays (*e.g.*, parts of the Marcellus shale play). The latter occurs because of various physical limitations (*e.g.*, topology and acreage limitations). The vertical rigs used for such applications are not included in the tabulation summarized in Figure 5-5.

As noted in Figure 5-5, overall there has been about a 75 percent increase in industry drilling activity for the shales, since the announcement of Marcellus and Haynesville shales in January 2008. Furthermore, while drilling activity for some of the shales has declined from its peak activity in 2010, drilling for the other shale plays is still increasing. However, the decline in overall horizontal drilling activity for the major shale plays is only about 3.5 percent from peak 2010 activity. The decline in drilling activity for the individual shale plays primarily represents the industry's response to sub $4.00 per MMBTU gas prices, which has occurred because of the buildup of excess supply over the last couple of years.

FIGURE 5-5: MAJOR SHALE HORIZONTAL RIG COUNT



Date	Fayetteville (AR)	Haynesville (LA, TX)	Barnett (TX)	Woodford (OK)	Eagleford (TX)	Marcellus (PA,WV)	Total
Jan-08	35	6	184	43	5	13	274
Jan-09	41	55	139	56	11	22	324
Jan-10	32	133	81	45	29	76	396
Jan-11	30	135	82	51	78	107	483
2010 Peak	36	154	95	59	75	107	501

CANADIAN SHALES

In addition to the six major U.S. shale plays there are two significant shale plays in Canada.[70] These include the Horn River shale play, which appears to have twice the gas-in-place as the Barnett shale play and is about 50 percent thicker than the Barnett shale play, and the hybrid Montney shale play.[71,72] Both of these plays are concentrated in northern British Columbia, with the Montney play extending into northern Alberta, while the Horn River extends into the Northwest and Yukon Territories. In addition, both plays are still in their early stages of development, as production for the Horn River shale play did not start in earnest until 2009.[73] A key factor that limits the rapid development of these plays is the lack of infrastructure (*e.g.*, pipeline and processing plants) in the region. Once the required infrastructure is built production should increase rapidly.[74]

[70] There is the potential for a third shale play in Canada, namely the Utica/Lorraine shale play in the Quebec and Ontario provinces. However, information in the public domain is limited and, as a result, it is too early to come to any definitive conclusions on this play.

[71] Exxon Mobil has characterized the Horn River play as a potential world class field. See “Exxon Shale-Gas Find Looks Big”, *Wall Street Journal*, July 13, 2009.

[72] The Montney play is relatively complex as it contains a conventional gas play near the Alberta border, an unconventional shale gas further to the west and a sand/siltstone formation that extends into western Alberta.

[73] Average 2010 production for both plays was approximately 0.7 BCFD.

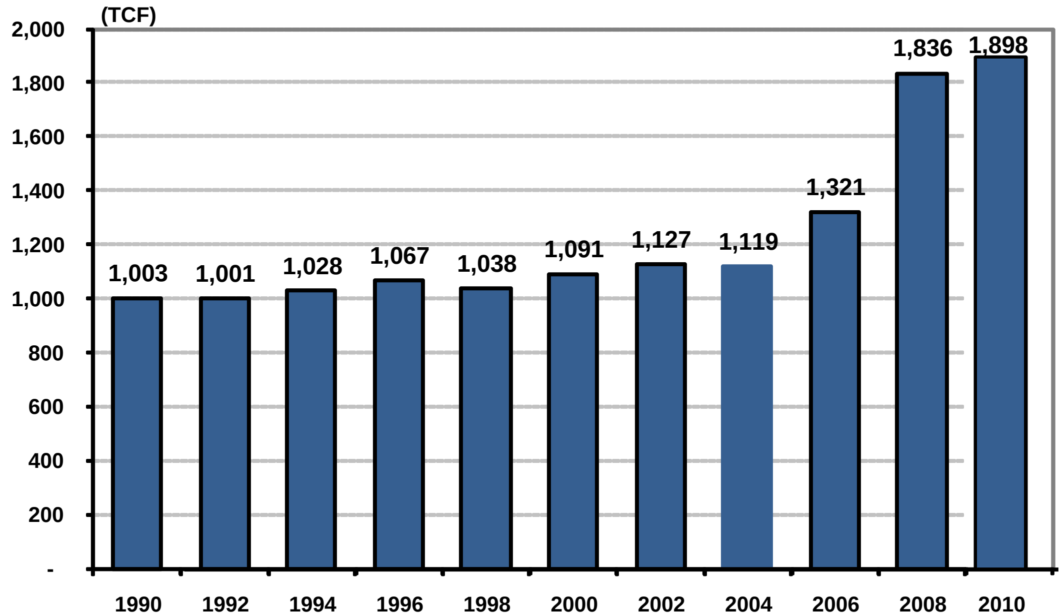
[74] The Groundbirch Pipeline for the Montney play came online at year end 2010 at an initial capacity of 0.23 BCFD with contracted volumes set to increase to 1.1 BCFD by 2014, while the Horn River Pipeline (*i.e.*, 0.5 BCFD initially, but expandable to 1.6 BCFD) is scheduled to come online in 2012.

RESERVES

Every two years the Potential Gas Committee (PGC) issues a report that assesses the gas resource potential for the U.S.[75] In their most recent bi-annual report the significance of the evolving shale plays within the U.S. and their prolific potential was clearly evident. As illustrated in Figure 5-6, the most recent report had the largest increase ever in the estimated gas resource base (*i.e.*, a 515 TCF, or 39 percent increase) and the industry's advancement of the shale plays were at the core of this increase. At present the shale reserves account for about 40 percent of the estimated technically recoverable (*i.e.*, about 616 TCF) reserves for the lower-48. This represents a significant change from the 2003 National Petroleum Committee report, which identified potential shale reserves as only 35 TCF.[76] Because of the advancements by the industry in the development of the shale reserve, over a period of about five years the amount of technically recoverable shale reserves increased by a factor of 18.

Furthermore, the Potential Gas Committee's bi-annual report, published in 2011, increases the assessment of reserve potential for the shale plays by 61 TCF to 1,898 TCF (for the United States).[77] The increase is likely due to the significant drilling activity and advancements that have occurred within the industry over the two year period.

FIGURE 5-6: TOTAL POTENTIAL NATURAL GAS RESOURCES



Source: Potential Gas Committee.

[75] The current assessment assumes neither a time schedule nor a specific market price for the discovery and production of future gas supply. Assessments of the Potential Gas Committee are 'base-line estimates' in that they attempt to provide a reasonable appraisal of what is consider to be the 'technically recoverable' gas resource potential of the United States.

[76] http://www.npc.org/Study_Topic_Papers/29-TTG-Unconventional-Gas.pdf

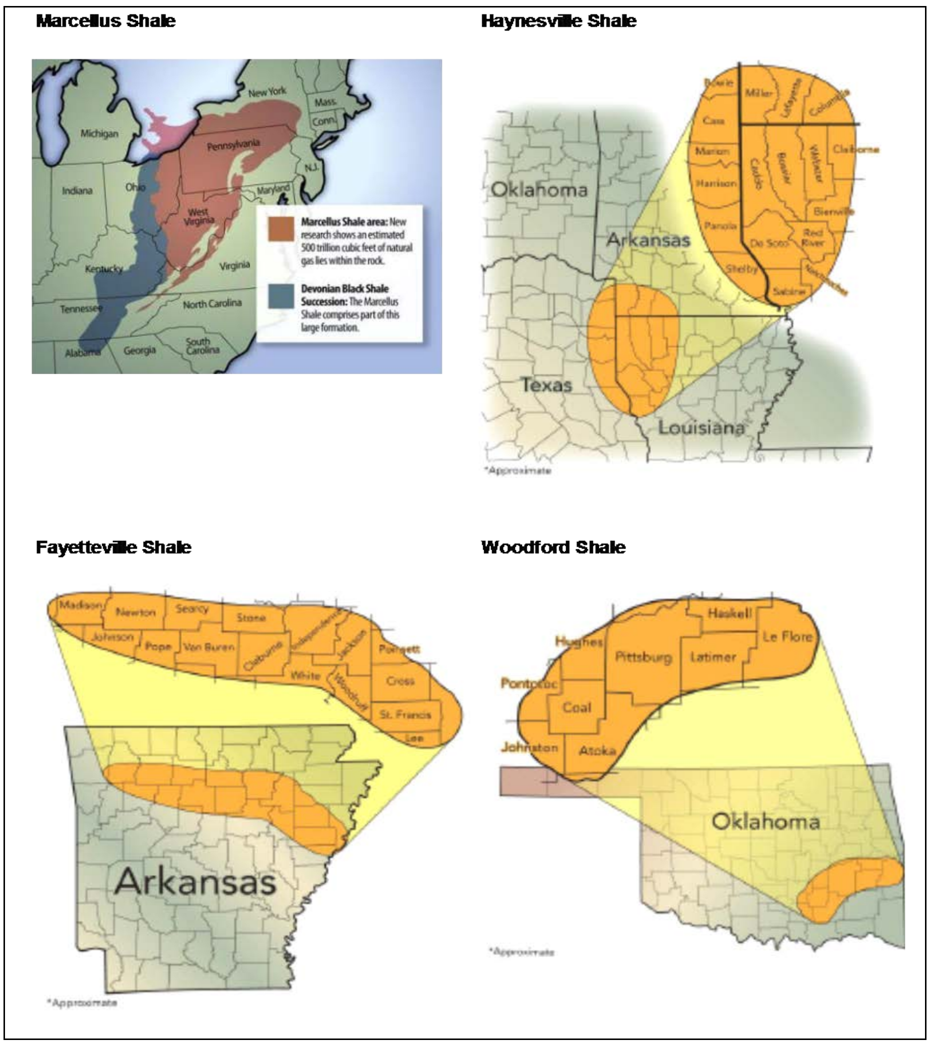
[77] http://www.potentialgas.org/

WELL ECONOMICS

AERIAL EXTENT

There are two major factors behind the transitional nature of the still evolving major shale plays, namely their large aerial extent and their superior well economics. Concerning the former, unlike most of the conventional gas plays, the major shales extend over large geographical areas covering millions of acres, or alternately thousands of square miles.[78] For example, the main fairway for the Marcellus shale play represents about 15 MM acres (23,500 square miles), while the Haynesville shale play has an aerial extent of between 5,000 and 5,500 square miles. Similarly, the Eagle Ford shale play is roughly 50 miles wide and 400 miles long, while the Fayetteville shale play extends across approximately 16 counties in northern Arkansas (*i.e.*, about 4,000 to 9,000 square miles).[79] To further place in perspective the large aerial extent of these shale plays, Figure 5-7 provides illustrative maps for selected major shale plays (additional maps are also in Appendix D).

FIGURE 5-7: AERIAL EXTENT OF SELECTED SHALE PLAYS



[78] 640 acres is the equivalent to one square mile.

[79] The Woodford and Barnett shale plays have been estimated to extend over about 2,500 and 5,000 to 8,000 square miles respectively.

IMPROVEMENT IN DRILLING TECHNOLOGY

One of the key factors behind the superior well economics for the major shale plays has been the extensive advances by the industry in the drilling and completion technology used to develop these shales. Furthermore, the industry is continuing to make advances in this technology with some in the industry opining that the industry currently is far from optimizing the technology to develop the shale plays. These advances in drilling and completion technology have lowered significantly the cost to develop the shales and, as a result, significantly improved their overall well economics. A few specific examples of such advances in drilling and completion technology for the shales are presented in Figure 5-8 through Figure 5-10, while Figure 5-11 presents a more generalized summary of the industry's advances in drilling and completion technology for the shales.

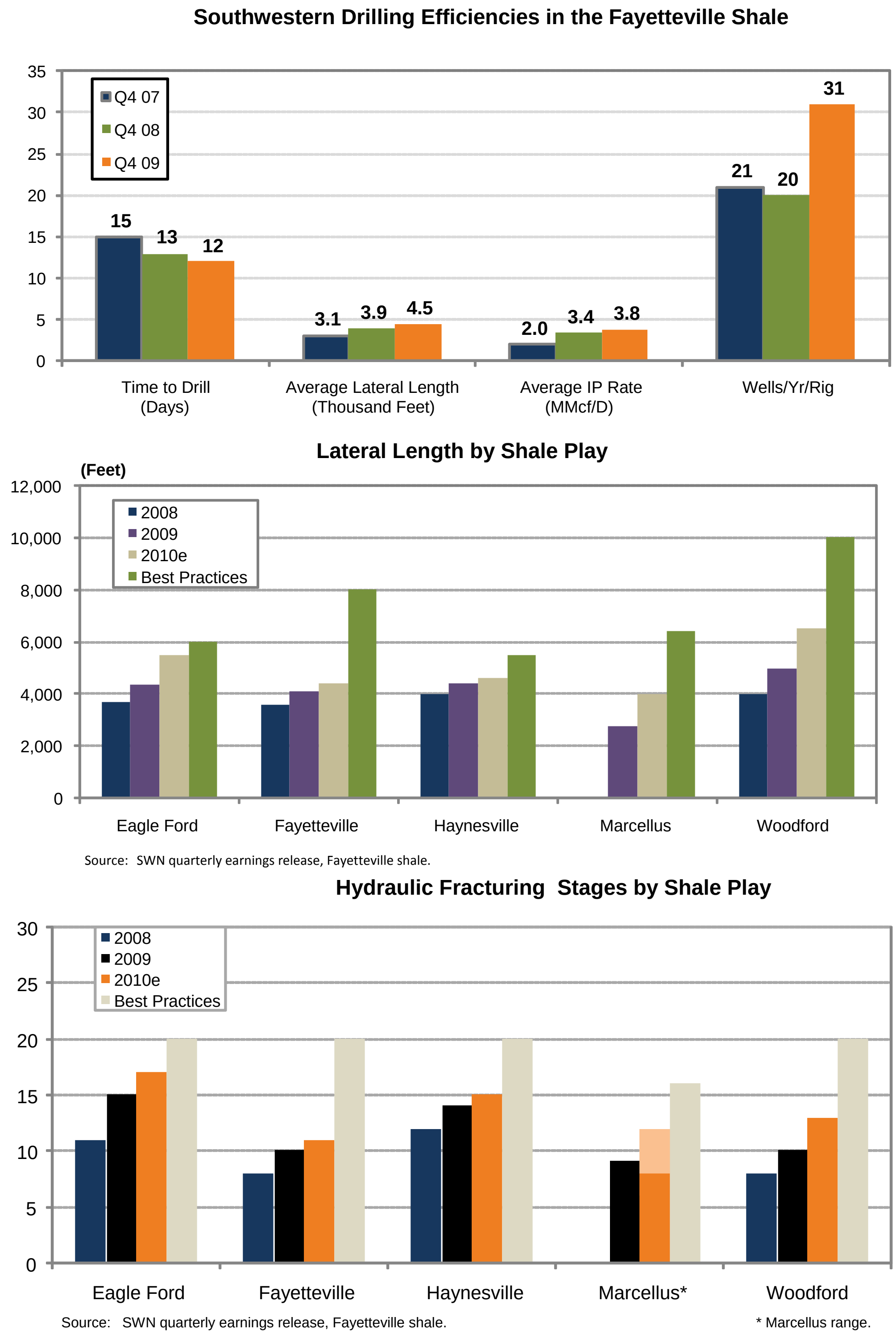
In Figure 5-8 the initial focus (*i.e.*, upper graph) is on the results of improvements in drilling and completion technology in the Fayetteville shale play by the industry leader for this play, namely Southwestern Energy, while the two lower graphs compare and contrast the improvements for the shale play with those for several of the other shale plays. As illustrated in the upper graph, for a period of three years (*i.e.*, 2007 through 2009) Southwestern was able to (1) lower the time it takes to drill a well about 20 percent, as well as (2) increase the number of wells drilled per year from a single drilling rig by about 48 percent. Both of these improvements help to significantly reduce drilling costs. In addition, Southwestern Energy was able to increase the length of the lateral used for their horizontal wells by 45 percent. This accomplishment, among other things, resulted in a 90 percent increase in the initial production (IP) rate for the average well, which significantly helps increase the well economics for the play.[80]

Similarly, the middle graph compares and contrasts the increases in the lateral length used in horizontal wells for other major shale plays with that accomplished for the Fayetteville shale play for a slightly different period (*i.e.*, 2008 to 2010), as comparable information does not exist for some of the shale plays for 2007. As illustrated, the improvements in the other major shale play range from approximately 12 to 58 percent.

Also, noted in the lower two graphs are the best practices in the industry for each play. The best practices within the industry for a given play are important because over time the industry, in order to optimize its economic return, tends to gravitate towards these best practices. As illustrated, current best practices for these important metrics are between about 5 and 95 percent higher than average 2010 results.

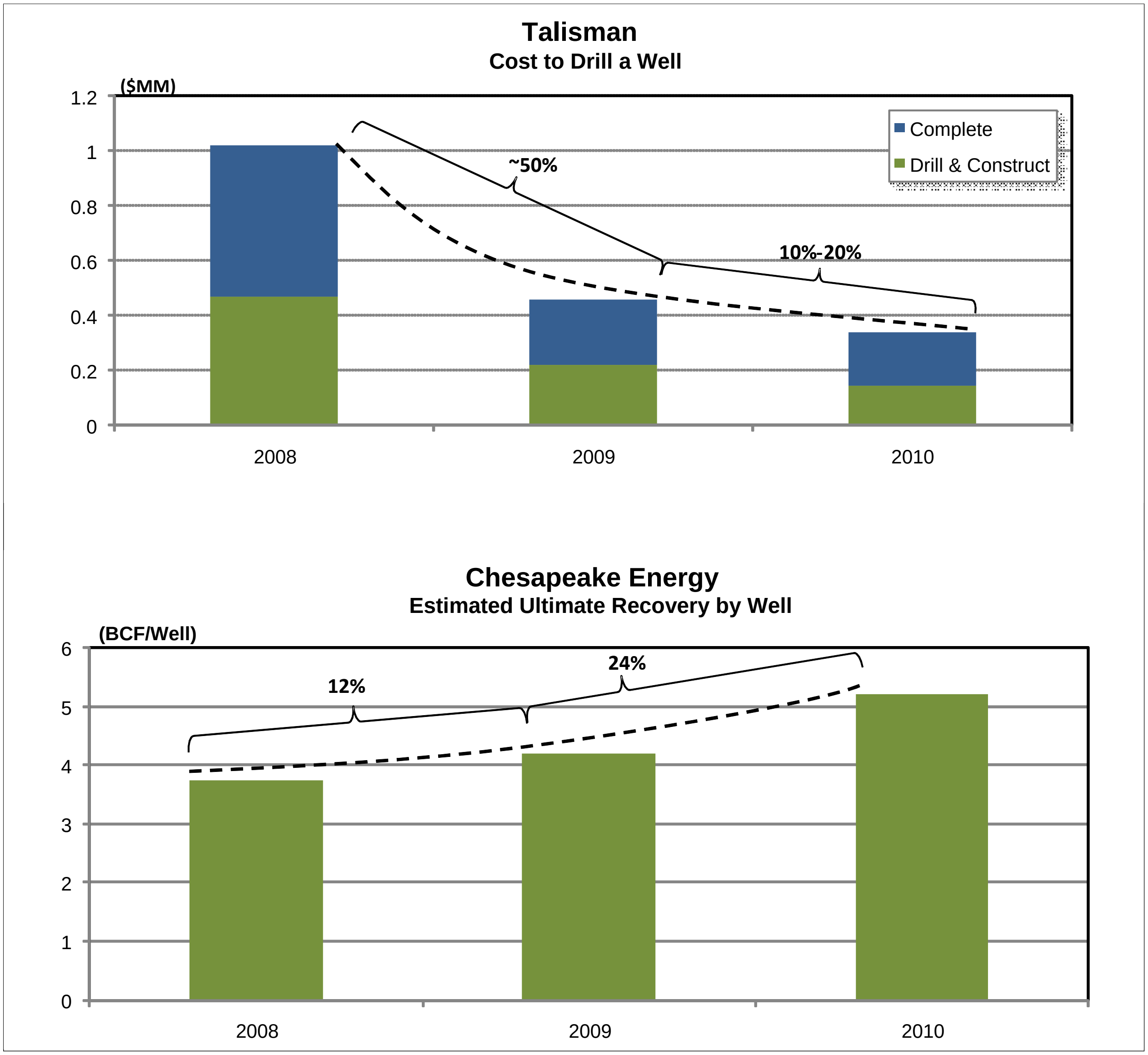
[80] Currently the breakeven gas price (*i.e.*, pretax 10% Rate Of Return (ROR)) for the core area of the Fayetteville shale play is about \$3.25 to \$4.25 per MMBTU, although this figure tends to be in a constant state of flux, because of advances in technology and drilling techniques, as well as other factors.

FIGURE 5-8: IMPROVEMENT IN DRILLING AND COMPLETION TECHNOLOGY FOR THE MAJOR SHALE PLAYS



Source: SWN quarterly earnings release, Fayetteville shale, Simmons & Company International.
**Marcellus range.*

Figure 5-9: Improvement in Key Well Economic Metrics for the Marcellus Shale Play

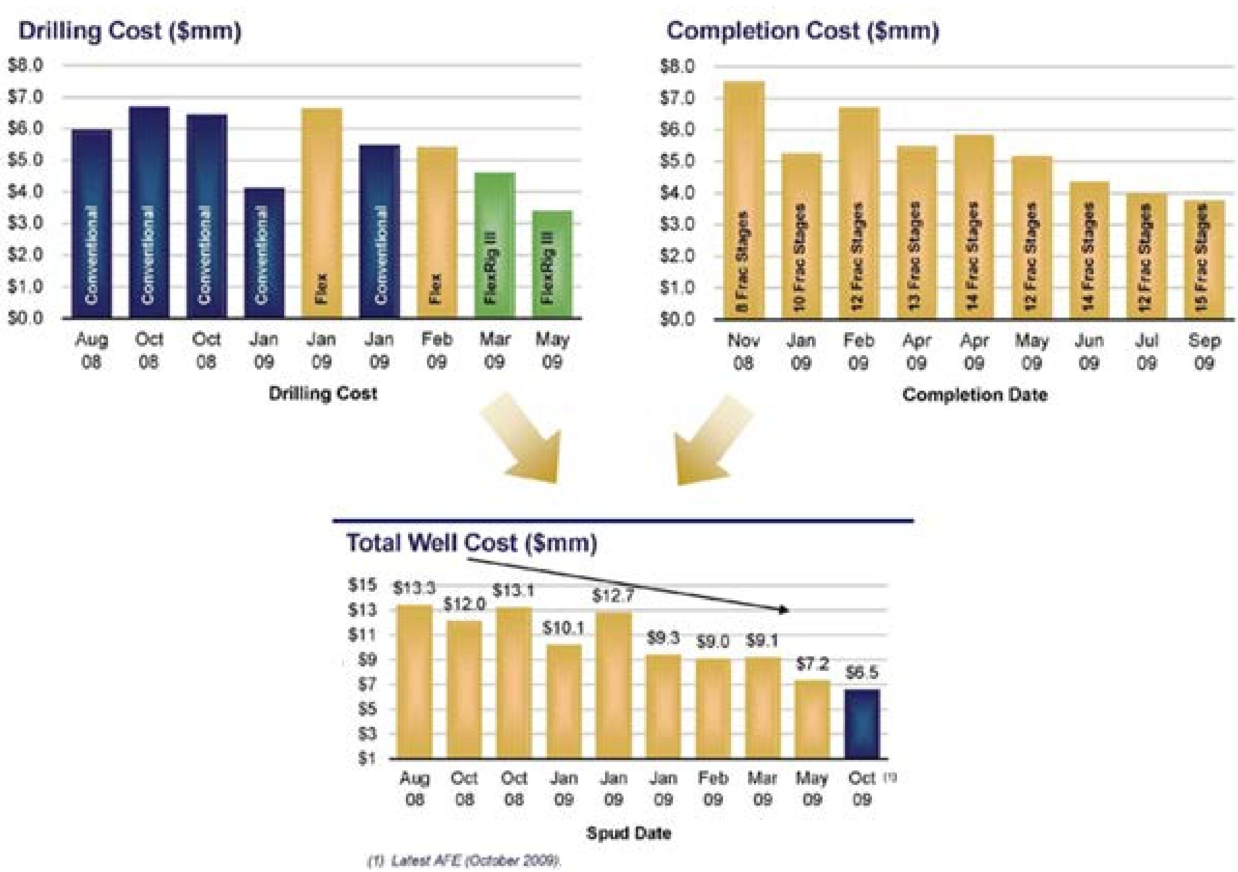


A similar comparison is done for the number of hydraulic fracturing stages per play, with the improvement from 2008 to 2010 ranging from about 25 to 63 percent depending upon the play, while current best practices are about 18 to 82 percent higher than the average 2010 results. Both the increase in the lateral length of the horizontal well and the number of hydraulic fracturing stages per well help increase the IP of the well, which in turn, increases the overall economics of the well.

In Figure 5-9, critical metrics for the well economics for the Marcellus shale play by two of the leading firms in this play are summarized. As illustrated, Talisman, for the 2008 to 2010 time frame, has been able to reduce its drilling and completion costs for a Marcellus shale well by about 60 to 70 percent, while Chesapeake Energy has been able to increase the estimated ultimate recovery (*i.e.*, BCF per well) by about 36 percent. Reductions in the capital cost per well and increases in the eventual amount of gas recovered per well both help improve the overall well economics for the play.

Lastly, in Figure 5-10 improvements in the two key cost components for the capital costs for a well in the Hayesville shale play are examined for the period 2008 to 2009. As illustrated, drilling costs over the time frame declined about 55 percent. A significant factor driving this phenomenon was the shift in the use of drilling rigs better suited for drilling in the Haynesville shale formation. This includes the more recent use of built-for-purpose Flex Rigs. With respect to completion costs improvements, they declined about 52 percent over the period, with a key driver behind this phenomenon being the increase in the number of fracturing stages per well, which usually involves the use of longer laterals. As a result of the combination of the improvement in (1) drilling costs and (2) completion costs, overall capital costs for the Haynesville shale well declined about 49 percent.

FIGURE 5-10: IMPROVEMENTS IN DRILLING AND COMPLETION COSTS FOR HAYNESVILLE SHALE WELLS



Other firms have been able to achieve similar results for the Haynesville shale play as those noted in Figure 5-10. For example, over the last two years, Chesapeake has been able to reduce the time to drill a Haynesville well from 70 to 54 days, or 23 percent. This reduces rig costs and improves overall well economics. Key factors in reducing the drilling time were (1) reducing the size of the hole, (2) the use of new drill bit technology and (3) the use of a modern fleet of rigs, which reduces rig down time. In addition, Chesapeake has taken actions to reduce the high cost of pumping services, which are required to fracture the well. In general, over the past couple of years, the cost of pumping services has been increasing because the demand for these services exceeds supply. In order to keep the cost of pumping services under control, Chesapeake has reduced surface treating pressures from 15,000 to 10,000 lbs, with the net effect of lowering costs $0.5 to $1.0 MM per well.[81]

While it is beyond the scope of this report to review each of the numerous changes in technology that has helped and likely will continue to help improve the overall well economics of the major shale plays, Figure 5-11 provides a general summary of the basic advances made by the industry to date.

In addition, there have been other forms of cost reductions within the industry, as the industry constantly adapts to changes within the industry and seeks to improve overall well economics. For example, recently completion costs have been increasing, primarily as a result of demand for such services exceeding the available supply. The industry has responded to this phenomenon by entering into long-term fracturing and completion contracts with third-party providers in order to stabilize this critical cost component. In addition, some in the industry have started to acquire their own fracturing and well completion teams. Pioneer reports this approach can save $1.0 MM per well. Similarly, vertical integration for rig ownership, particularly built-for-purpose rigs, has resulted in significant cost savings for some operators.

[81] Petrohawk is another firm that has undertaken similar efforts to reduce pumping costs.

FIGURE 5-11: ADVANCES IN EXPLORATION AND PRODUCTION TECHNOLOGY

One of the keys to unlocking the potential of the shale gas reserves has been a series of advances in E&P technology, which when applied in combination have made the shales the most prolific and economical plays within North America. The material below briefly summarizes these changes in technology.(1)

I. Major Technological Advances

A. **Fracturing:** The development of a slickwater fracturing system that includes a few additives.

B. **Horizontal Drilling:** The development of horizontal drilling techniques with 2,500 to 5,000 feet laterals along the fracture and, in some cases, laterals up to 10,000 feet. This technique, in large part, has replaced vertical wells.

C. **Multi-Stage Fracs:** The use of 10 to 20 or more frac stages to increase fracture-to-shale contact with the formation.

D. **Micro-Seismic Techniques:** The use of micro-seismic techniques to monitor in real-time stress changes created by fracs in an offset well to divert fractures in an adequate well into non-stimulated zones.

II. Other Advances in Technology

A. **More information** through the use of (1) 3D seismic, (2) geologic mapping, (3) cores, (4) petrophysical studies, (5) openhole logs, (6) diagnostic fracture injection tests, (7) fluid efficiency tests, (8) tracers, (9) stimulation behavior analysis, (10) flowback information and (11) production response analysis.

B. **Enhance and stabilize production** by improving the development, placement, and longevity of small fractures, such as fissures, microcracks or opened laminations.

C. **Hybrid Fluids:** In cases where slickwater hydraulic fracturing does not work the use of a hybrid fluid job to open fissures with a more viscous fluid with proppants (sized particles added to fracturing fluids to hold fractures open) .

D. **Water Use Techniques:** A still evolving area of industry technology to both minimize overall water requirements and minimize water disposal requirements. Included in these technologies are GE's mobile evaporator and Aquatech International's Frac Prue On-Site Mobile Treatment System.

III. Results

Among other things the combination of these technologies have increased recovery rates up to 50 percent, in some cases, versus the perception a decade ago that the recovery rate for the shales was about two percent. At present, the typical average is in the 15 to 35 percent range. In addition, production costs have declined – in some cases, dramatically.

(1) Oil and Gas Journal, September 27, 2010.

EMERGING SHALE PLAYS

In addition to the six major shale plays, there are a series of still emerging shale plays that over the long-term could make a significant contribution to the U.S. supply portfolio. To date there have been discoveries of approximately 46 shale plays in the U.S., however, some of these are not commercial and most of the remainder are in an embryonic stage of development. With respect to the latter, Figure 5-12 summarizes the current status for 18 of these shale plays that still are in the beginning stage of development. Over time, it is anticipated that as the industry advances its investigation of these shale plays that some of them will become commercially viable, particularly as gas prices approach $6.00 per MMBTU (gas prices are currently at about $4.00 per MMBTU). Furthermore, while it is unlikely that any single one of these emerging shale plays will be as prolific as the current six major shale plays, the combined impact of some of these plays transitioning into commercially viable plays likely will represent a significant contribution to the overall U.S. gas portfolio. A case in support of this observation is Occidental Petroleum's almost stealth effort to acquire acreage and begin to develop the California shales. For example, the firm is expanding infrastructure to support the further development of California shales[82] and recently predicted that in another decade California shale could be Oxy's largest operating unit.[83]

FIGURE 5-12: SHALE PLAYS STILL IN THEIR EARLY STAGE OF DEVELOPMENT

Shale Play	Basin	Comment
I. Promising Plays		
In Evaluation Stage		
Pearsall	South Texas	6 to 10 MMCFD; dry gas.
Collingswood	Michigan	2.5 MMCFD
Mancos	Unita (UT)	Some activity; 1 to 5 BCF.
Lower Huron	Appalacia (WV/KY)	Some activity; <1 BCF; not deep.
Gothic	Paradox (UT)	Needs higher prices; 3 MMCFD; capex = $4 MM.
Hovenweep	Paradox (UT)	Needs higher prices; 3 MMCFD; capex = $4 MM.
New Albany	Illinois (IN/IL)	Needs higher prices; 2 MMCFD; EUR < 1 BCF.
Needs Testing		
Manning Canyon	Unita (UT)	Very thick; relatively deep.
Monterey	California	Relatively rich with 5-10% TOC.
McClure	California	Relatively rich with 5-10% TOC.
Lewis	San Juan (NM)	Relatively deep.
II. Plays With Limited Potential		
Floyd	Gulf Coast (MS)	70% clay limits fracturing.
Barnett-Permian	Permian (TX)	< 1 MMCFD.
Bend	Palo Duro (TX)	Disappointing test wells.
Pierre	Raton (CO)	Shallow but EUR < 1 BCF.
Mancos	Raton (CO)	Shallow but EUR < 1 BCF.
Niobrara	Raton (CO)	0.4 to 1.8 MMCFD.
Barter	Vermillion (WY)	1 MMCFD.

Source: Oil & Gas Journal, Natural Gas Week and Inside FERC's Gas Market Report

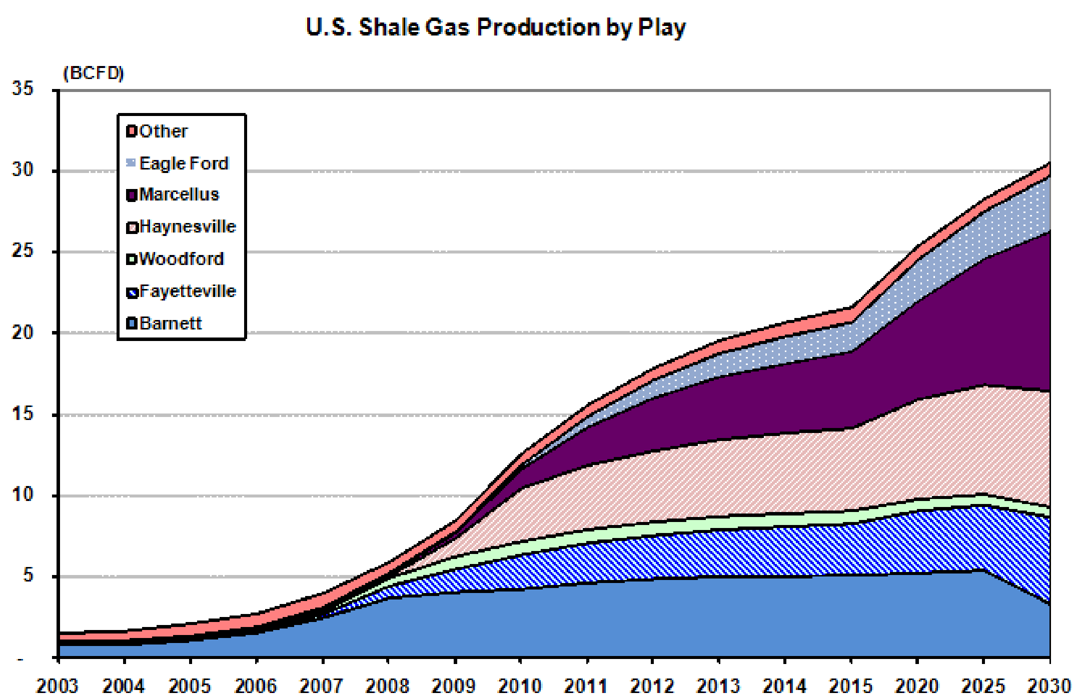
[82] Last year Oxy increased its processing plant capability by 90 MMCFD and plans to increase it another 200 MMCFD in early 2012.
[83] "Oxy Developing California Shale Assets Stealthily, Output Rising", *Natural Gas Week*, February 28, 2011, p. 1 ff.

Outlook

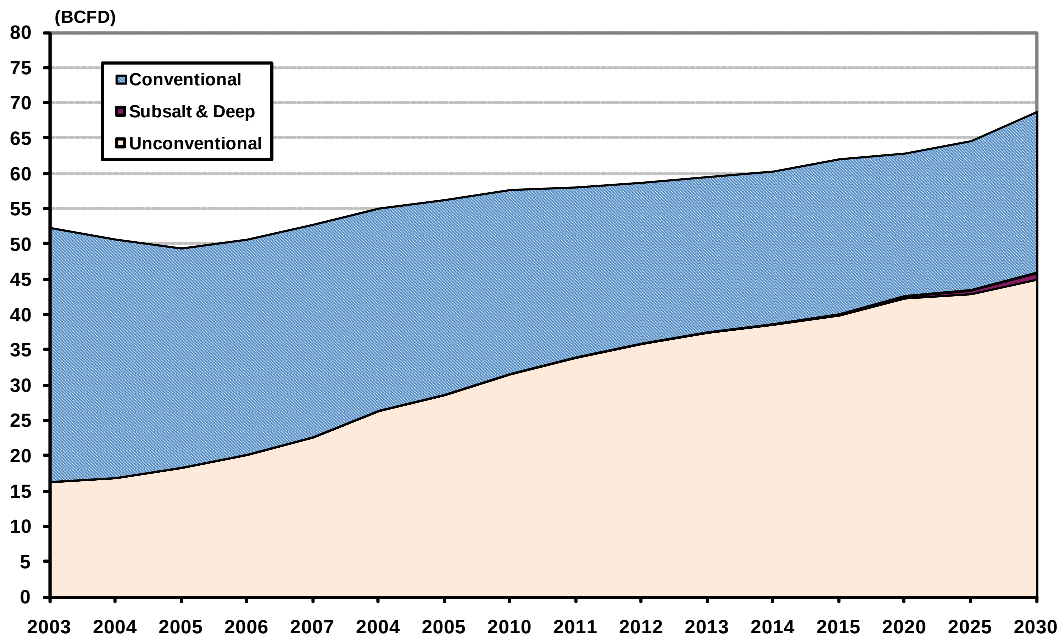
In addition, to currently making a significant contribution to the U.S. supply portfolio, the shales, because of their prolific nature, likely will make a significant contribution to the U.S. supply portfolio for an extended period of time—potentially doubling over the next 20 years. Furthermore, with the possible exception of Rockies production, the shales likely will be the only category of gas to grow over this period of time, as increased shale production basically will represent the entire growth in U.S. gas production for the next two decades. As a result, shale gas production will continue to increase as a percentage of total U.S. gas production and eventually will reach 45 percent of total production, which is well above the three percent it represented in 2003. Lastly, this assessment could prove to be conservative, since at present this gas supply model does not reflect the likelihood of production from any of the emerging shale plays over the next two decades. It also is noteworthy that the combination of shale, tight sands and Coal-bed Methane (CBM) production (*i.e.*, all the unconventional sources of gas production) will likely represent approximately 67 percent of total U.S. production in about two decades.

Figure 5-13 summarizes the current outlook for shale production over the long-term. As illustrated, production from both the Marcellus and Haynesville shale plays are expected to surpass production levels from the Barnett shale play. In addition, production from the Fayetteville shale play is expected to approach current production levels from the Barnett. With respect to the Canadian shale play, it is too early to ascertain if production from the Horn River shale play, which is about 50 percent thicker than the Barnett shale play, will exceed production from the Barnett shale play.

Figure 5-13: Long-Term Outlook For Shale Production



U.S. Natural Gas Production by Major Component



Note: Excludes production associated with the Alaskan pipeline.

Impact on Natural Gas Industry

In addition to the transitional shales having a significant impact on the domestic production profile and the outlook for gas prices, the phenomenon of the shales has affected the natural gas industry in a number of other ways. The following briefly summarizes these other changes in order to provide the reader with a greater perspective on the full impact of the transitional shales.

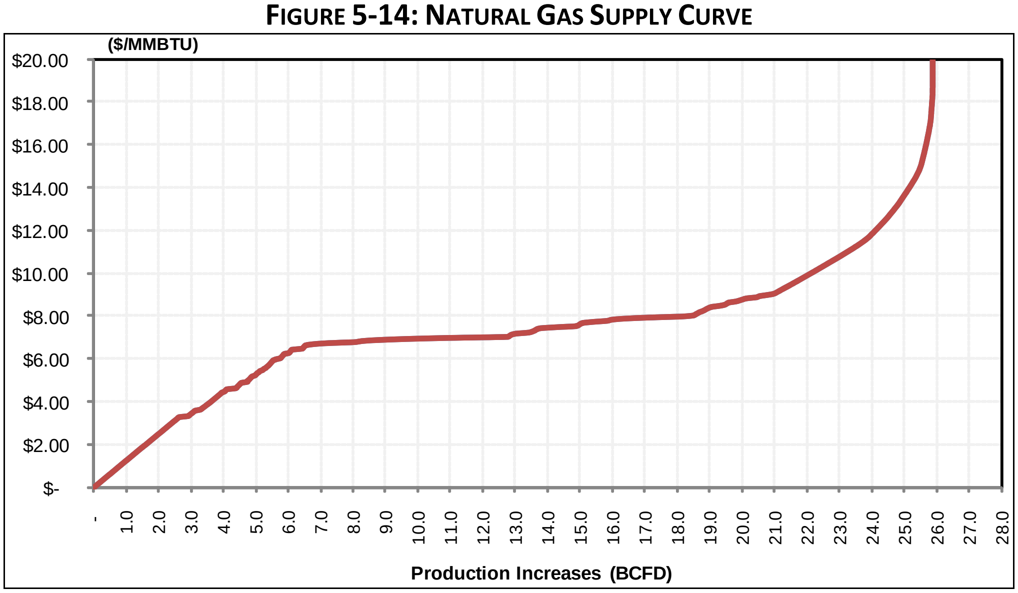
- **Decline in Conventional:** A shift away from the development of the traditional conventional resource plays in the industry, because of their inferior well economics. This represents a major strategic shift for the industry.
- **Major Shift From Exploration to Development:** An adoption of a 'semi-factory' development process to develop these shales, which is in sharp contrast to the conventional use of both geological and geophysical science to seek out higher risk plays. This, in turn, has resulted in significant organizational changes within E&P firms with the industry, with less emphasis on exploration and greater emphasis on drilling and production technology.
- **New Strategic Approach:** A shift in company strategies from being high-risk, high-reward firms to being high-volume, low-margin firms.
- **Joint Ventures:** The combination of the deteriorating financial positions within the industry and the high capital requirements to develop the millions of acres required as part of the shale boom has resulted in the industry entering into a series of joint ventures. The latter, in essence, represents a selling off of a portion of their acreage positions in an effort to gain access to capital. As of year-ending 2010 there have been 61 joint ventures, acquisitions and similar type

transactions for the shales, with 28 of them being joint ventures. A total of $111 billion has been spent on these 61 transactions.

- **Excess Supply:** The effort by the industry to maintain drilling activity at a high enough level to preserve their acreage positions has resulted in an intermediate-term period of excess supply, which has exacerbated the downward trend in gas prices.[84] A contributing factor to this phenomenon is the large capital raised in the series of joint venture agreements, particularly the multi-year, drill carries associated with these joint ventures.

- **Flat Supply Curve:** The very economic and very prolific shales have changed the shape of the supply curve for natural gas. Figure 5-14, illustrates the shape of the gas supply curve for 2020, with the supply curves for 2025 and 2030 having a very similar shape.[85] As illustrated in Figure 5-14, the gas supply curve is very flat, particularly since the critical area of the supply curve is for annual production increases of between eight and nine BCFD. The latter represents the amount of new production that needs to be developed to both replace the annual decline in existing production and the annual increase in demand. One of the most significant aspects of a flat supply curve is that it results in a very robust assessment of natural gas prices. As a result, changes in demand and supply assumptions result in rather modest changes in the outlook for gas prices, which is one reason the NYMEX futures strip[86] does not exceed $6.00 per MMBTU until 2015, or exceed $7.00 per MMBTU until 2020. This relatively flat gas supply curve and the associated robust nature of the gas price projections for the current industry are very different from what existed for the industry prior to the emergence of the shales.

FIGURE 5-14: NATURAL GAS SUPPLY CURVE



[84] Most leases include use-it-or-lose-it provisions that require a well to be drilled on a parcel of acreage within a certain time period or the lessor loses both the lease and its upfront payment.

[85] This supply curve is derived from the EVA Long-Term Gas Supply Model with industry model's yielding similar type curves. The reason for focusing on the supply curve for a single year is to more accurately reflect the constraints that exist within the industry. For example, even though one source of gas may be very expensive within any given year the amount of gas that can be developed is limited by a series of constraints within the industry, for example, pipeline takeaway capacity, the number of rigs that are available for a specific play and others.

[86] The NYMEX Strip, or "12-month strip" is the average of the daily settlement prices of the next 12 months' futures contracts, and is a good indicator of where natural gas prices are for the next year.

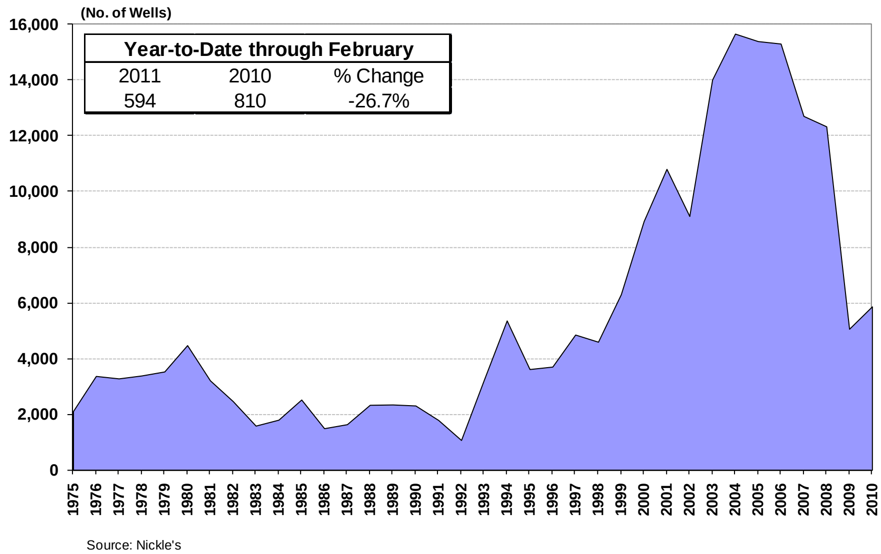
- **Canadian Production:** Since Canadian production is the furthest from the major U.S. markets and has the highest basis differentials, drilling in Canada, particularly for conventional production, has been affected adversely by the decline in U.S. gas prices. This decline in Canadian production has caused a significant decline in gas exports to the U.S. This represents a significant departure from the historical supply portfolio for the U.S.
- **LNG Imports:** There has been a complete reversal in the outlook for U.S. LNG imports. Earlier in the decade the prevailing industry opinion was that there would be significant growth in U.S. LNG imports in order to fulfill a perceived supply gap. However, as a result of recent events and the associated decline in gas prices, the perception by many industry observers is that the U.S. will not need any U.S. LNG imports for the next decade or longer, except for the small amount required for specific regional and seasonal requirements. This represents a major change in the previously projected U.S. supply portfolio.
- **World Gas Prices:** The removal of the U.S. as one of the major LNG importing markets has altered significantly the global LNG supply and demand fundamentals, with one of the key results being a decline in global gas prices, particularly global spot LNG prices.
- **Long-Term Contracts:** While there are only a few examples which one can reference, there has been an initial shift by the industry towards a more diversified portfolio of gas contracts. The latter includes serious efforts by both consumers and producers to negotiate long-term gas supply contracts with some form of fixed gas prices. This represents a significant shift in industry thinking from the last 20 years of being, in essence, 100 percent dependent upon spot gas supplies. Because the definition of "long term" is still evolving, no precise definition is possible at this time.

CANADIAN IMPORTS

With one significant exception, Canadian production has become a marginal source of supply for the U.S. market. This is particularly true for the Canadian conventional production within Alberta. Canada's transition into a role as a marginal supplier is due to both the higher well economics for the region (*i.e.*, particularly when compared to the core areas of the U.S. shales) and the larger basis differentials for the region, as Western Canada is the farthest producing region from the major U.S. markets.

As result of this marginal status, gas-drilling activity has declined sharply, as illustrated in Figure 5-15. Even though there was some modest recovery in Canadian gas-directed drilling activity, annual well completions in 2010 were still 60 percent below the prior peak. This decline in drilling activity has caused Canadian production to also decline sharply and current expectations are for further declines.

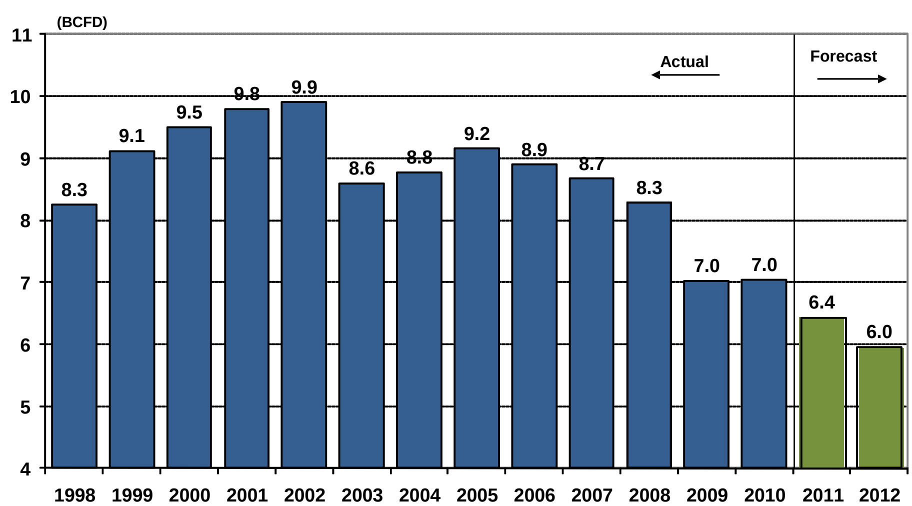
FIGURE 5-15: CANADIAN GAS WELL COMPLETIONS



While the development of the Horn River and Montney plays likely will result in a recovery in Canadian production levels, not all of this incremental production will be earmarked for the U.S. market. This occurs because in 2015 Canada will start exporting gas to other countries via Phase I of the Kitimat liquefaction terminal, which has a capacity of 0.7 BCFD and is scheduled to be online in 2015. Both Apache and EOG Resources, which are major Horn River developers, have agreed to supply the Kitimat terminal.[87]

The net result of this projected further decline in Canadian production is that exports to the U.S. will once again begin to decline. While in 2010 Canadian exports to the U.S. were flat, going forward it is anticipated that the decline that started in earnest in 2005 will reoccur, as illustrated in Figure 5-16.

FIGURE 5-16: NET CANADIAN TRANSACTIONS



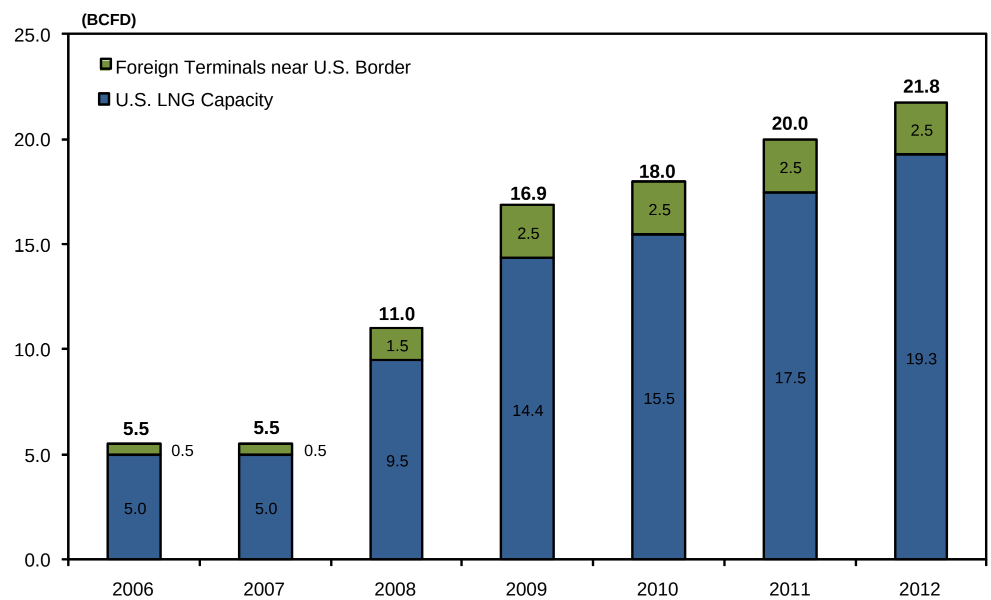
[87] The Kitimat project is now owned 40 percent by Apache, 30 percent by EOG Resources and 30 percent by Encana.

LNG IMPORTS

REGASIFICATION TERMINALS

The third component of the U.S. gas supply portfolio is LNG imports. At the beginning of the last decade the general industry consensus was that increased LNG imports would be used to fulfill a forecasted gap between U.S. supply and demand. The industry's response was to propose over 90 new regasification terminals plus expansions at the four existing terminals – some of which were mothballed at the time. Of these 90 proposed new projects, 11 eventually were built which increased the LNG regasification capacity serving the U.S. market to about 22 BCFD, as illustrated in Figure 5-17.[88] As noted in Figure 5-17, this regasification capacity can be divided into two categories, namely those terminals within U.S. territory and those terminals that are in neighboring countries, but primarily designed to serve the U.S. market.

FIGURE 5-17: U.S. LNG REGASIFICATION CAPACITY



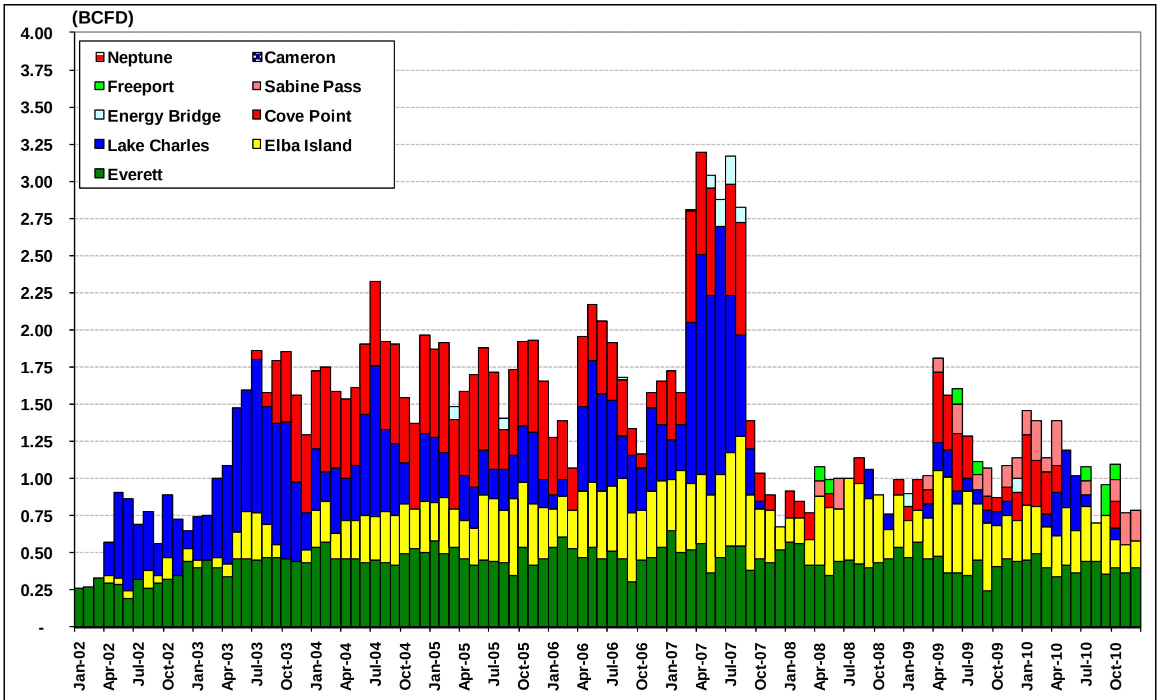
U.S. LNG IMPORTS

U.S. LNG imports in 1998 were approximately 0.2 BCFD and grew rather steadily to about 1.8 BCFD in 2004. However, since that time they have ranged from one to 1.8 BCFD, with LNG imports in 2010 being about 1.1 BCFD. Figure 5-18 illustrates the monthly imports by terminal for the last eight years. Going forward it is expected that U.S. LNG imports likely will remain in the one to two BCFD range for at least 10 years.

---

[88] Appendix C contains a map illustration of the location of the various regasification terminals, as well as a detailed listing of the individual terminals and their capacity.

FIGURE 5-18: MONTHLY LNG IMPORTS BY TERMINAL



Source: DOE and LCI. Note: April and May estimated and excludes Altamira.

LIQUEFACTION CAPACITY[89]

In light of the fact that U.S. regasification capacity is so over built and U.S. shale production is so prolific, several developers are considering converting their regasification terminals to liquefaction facilities in order to export U.S. LNG.[90] The Kitimat facility in British Columbia was the first to convert their project. Phase I (0.7 BCFD) for this liquefaction facility is scheduled to go online in 2015, with Phase II still a possibility. Other projects actively pursuing converting their projects to liquefaction facilities include Cheniere's Sabine Pass terminal (LA), Dominion's Cove Point terminal (MD) and the Freeport terminal (TX). While this latter group of projects will all likely receive permits, the permits limit exports to a select group of countries (*i.e.*, limited to the 15 countries that have free trade agreements with the U.S.).[91] In addition, it is unclear if these proposed liquefaction projects will be successful in obtaining long-term export contracts, which are a prerequisite to obtaining financing. The Kitimat project, which serves the Pacific Basin, rather than the Atlantic Basin, was successful in obtaining long-term contracts.

[89] As a point of reference, the global LNG industry uses the Wobbe Index as its key metric for assessing the heating value of gas, whereas the U.S. natural gas industry relies primarily upon a volumetric heating value (*i.e.*, BTU per cubic foot). The Wobbe Index incorporates the specific gravity of the gas stream and is defined as the 'BTU per cubic foot divided by the square root of the specific gravity of the gas stream'. The Wobbe Index is, in essence, measuring the quantity of gas, or heating value, that will flow through a hole of a given size (*e.g.*, a pipeline) in a given amount of time. For example, large molecules, such as butane, have a greater volumetric heating value, but will not flow as fast through a hole of a given size, while methane molecules have a lower heating value but would flow faster through a hole of a given size.

[90] The U.S. already has one liquefaction facility in Kenai, Alaska (187 MMCFD), however it is scheduled to shut down in May 2011.

[91] Currently, the Free Trade Agreement nations are Canada, Mexico, Dominican Republic, El Salvador, Guatemala, Honduras, Nicaragua, Chile, Peru, Morocco, Oman, Jordan, Bahrain, Australia and Singapore.

ARCTIC GAS PIPELINES

There is considerable uncertainty surrounding the last component of the U.S. gas supply portfolio, which is the potential for offshore Arctic gas supplies from both Alaska and Canada being transported to the Lower-48. There are two proposed Arctic gas pipeline projects, namely the smaller Canadian MacKenzie Delta project (*i.e.*, 1.2 BCFD which can be expanded to 1.8 BCFD)[92] and the larger Alaskan pipeline project (*i.e.*, approximately 4.0 BCFD which can be expanded to 5 BCFD).[93] At present there are two proposals for an Alaskan pipeline as noted below, but only one will be built:

- **AGIA Pipeline:** TransCanada and ExxonMobil are sponsoring the AGIA Pipeline.[94]
- **Denali Pipeline:** BP and Conoco are sponsoring the Denali Pipeline.[95]

At present the AGIA pipeline proposal appears to be the more likely option because of the financial problems facing both BP and Conoco.

Probably the most critical issue for these pipelines has been the delays in project schedules, primarily because of delays in obtaining the required permits.[96] For example, the smaller MacKenzie Delta pipeline originally was scheduled to come online in 2011 and now the schedule is for late 2018 at the earliest. Similar delays have occurred for the Alaskan pipeline project. Estimates of when the Alaskan pipeline project will come online tend to range from late 2021 to 2023. However, others, such as the EIA, opine that the project may not be economically viable until after 2035.[97]

Adding to the uncertainty for these large projects is the impact the transitional shales have had on U.S. natural gas prices. In general, these projects likely require gas prices in the $6.50 to $7.00 per MMBTU range at the AECO hub in Canada in order to be economically viable, with some industry observers citing even higher gas prices. As a result, the exact timing of either Arctic gas pipeline project still represents a significant point of uncertainty within the industry.

[92] The 807 mile MacKenzie Delta Pipeline in the Northwest Territories will use a 30" gas line and a 10" NGL line, initially have four compressor stations and will cost approximately $16.2 billion to complete (*i.e.*, approximately $7.8 billion for the pipeline, $3.5 billion for gathering lines for the three fields, a treating plant and a parallel NGL pipeline, and $4.9 billion for the development of the three fields). The pipeline will involve transport of both liquids and gas to Norman Wells (*i.e.*, 298 miles) and then to Boundary Lake, AB where it will interconnect with the Alliance and/or TransCanada pipelines. The initial capacity of the system will be 1.2 BCFD however the pipeline can be expanded to 1.8 BCFD. The project sponsors are four producing companies that hold the gas reserves and will own the gathering system (Imperial Oil-the lead project manager, ConocoPhillips, Shell, and ExxonMobil), and the Aboriginal Pipeline Group which holds 1/3 interest in the pipeline.

[93] See Appendix C for a map of both pipelines.

[94] The TransCanada project (*i.e.*, AGIA pipeline) would be 1,750 miles long, cost $26 billion and have an initial capacity of 4.5 BCFD that could be expanded to 5.9 BCFD with compression only. The project would extend from a gas treatment plant near Prudhoe Bay, AK to Boundary Lake, AB, where it would connect to TransCanada and/or Alliance and major markets.

[95] The BP/Conoco project (*i.e.*, Denali pipeline) would be 2,100 miles to Boundary Lake, AB, with 48" to 52" pipe that would cost $30 billion and have an initial capacity of 4 BCFD, which could be expanded to 5 BCFD. The Alaskan segment would extend 750 miles from Prudhoe Bay to Fairbanks, and then follow the TransAlaskan Highway to the Alaska/Yukon border. At the Canadian border, Denali's Canadian affiliates would continue 1,000 miles across the Yukon and BC to the Alberta border, and then extend another 1,500 miles across North Dakota, Minnesota, Iowa, and Illinois to Chicago if required. The project includes a gas treatment plant on the Alaskan North Slope.

[96] In March 2011 the MacKenzie Delta pipeline finally received a permit from the Canadian National Energy Board.

[97] In its 2011 Annual Energy Outlook, EIA removed the pipeline from its reference case, citing this change is a result of increased capital cost assumptions and lower natural gas wellhead prices, largely due to the emergence of shale gas in the market, which make it uneconomical to proceed with the project over the projection period.

Observations

The transitional shales have had a significant impact on the natural gas industry. From many perspectives the results to date from the shales are unprecedented. For example:

- Largely because of advancements in technology, the assessment of technically recoverable shales has increased by a factor of 18 in the last five to six years. More specifically, the Potential Gas Committee in its last bi-annual report increased its assessment of the U.S. gas resource base by 39 percent (*i.e.*, the largest increase ever). Almost all of this increase was due to the shales.
- Shale gas production has increased 15 BCFD between 2003 and year-end 2010.
- Shale gas production now represents about 26 percent of U.S. production, whereas in 2003 it was only three percent.
- The well economics for the shales are superior. Best practices for shales yield breakeven (*i.e.*, includes a 10 percent pre-tax ROR) gas prices of $5.00 per MMBTU or below.
- Based upon the current NYMEX and several independent gas price projections, the natural gas industry appears headed for a long period of low, stable gas prices.

The impact of the transitional shales on the natural gas industry is not limited to just production and reserves, as this phenomenon has (1) caused the industry to adopt new strategic approaches (*e.g.*, high-volume, low-margin strategies), (2) reduced the need for LNG imports; (3) caused Canadian conventional production to become a marginal source of North American gas supply; (4) impacted world gas prices, and (5) others.

Chapter 6—Regionality

One of the factors that can make coordination between the natural gas and electric power industries so challenging is that both industries have significant regional differences. For example, over 50 percent of total primary gas demand is concentrated in just 13 states (*i.e.*, 27 percent of the states), while for the power sector just three states account for 45 percent of total electric sector demand. Furthermore, these regions where natural gas consumption is concentrated tend to be the same areas with the longest history with gas being used in the power sector, and the areas where the coordination efforts between the two industries is the greatest, primarily because of long period to work out the fine details of their mutual interface.

This chapter briefly reviews the regional differences for each of these two industries. In the case of the natural gas industry the regional differences for both natural gas production and consumption are assessed. For the electric power industry the large differences in the fuel profiles for the various regions are highlighted. Furthermore, Appendix E presents the fuel profiles for each electric region and how they have changed over time.

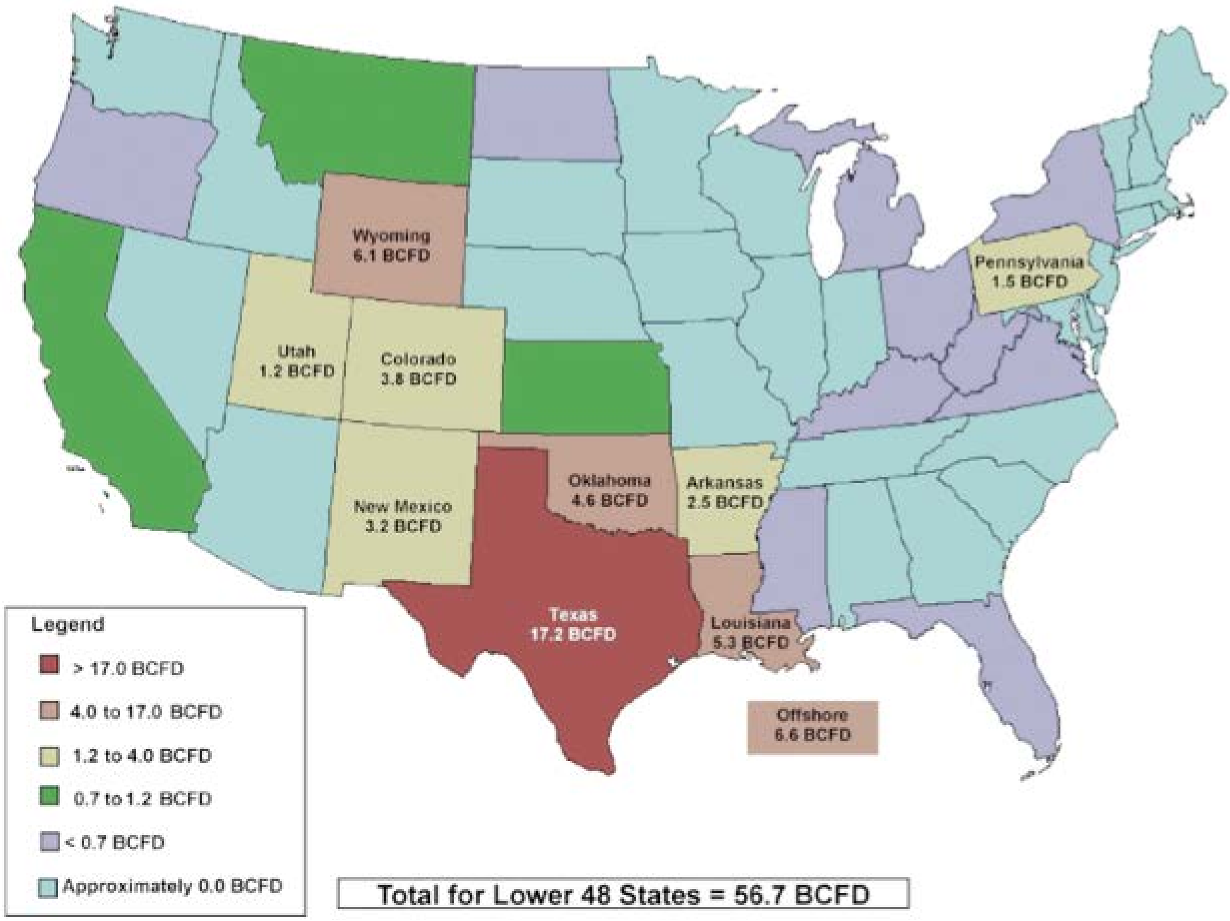
NATURAL GAS INDUSTRY PRODUCTION

While the transitional shales are causing a significant change in the infrastructure of the U.S. supply portfolio, domestic gas production is still highly concentrated. Figure 5-2 presented a map of the major gas production basins, or areas, in the U.S. Figure 6-1 provides an additional perspective for lower-48 gas production by highlighting the amount of dry production for each state. As illustrated, Texas is by far the leading state for natural gas production, as it currently accounts for about 30 percent of lower-48 gas production. The next three largest states plus production offshore Texas and Louisiana[98] account for almost another 40 percent of total lower-48 gas production. Basically, Texas, plus the states and offshore areas surrounding account for about 60 percent of total lower-48 gas production with Wyoming accounting for an additional 10 percent.

With respect to the remaining U.S. gas production, the next five largest gas producing states, which with the exception of Pennsylvania (*i.e.*, the Marcellus shale), are concentrated in the West, account for approximately another 20 percent of lower-48 production. As a result, slightly over 90 percent of lower-48 gas production exists in 10 states plus the surrounding offshore area. The remaining eight percent U.S. production is spread out across 13 states, with half of the states within the lower-48 having either having de minimus gas production levels or no natural gas production.

[98] 3.8 percent of total offshore production occurs in the state waters offshore Alabama.

FIGURE 6-1: 2010 DRY PRODUCTION BY REGION



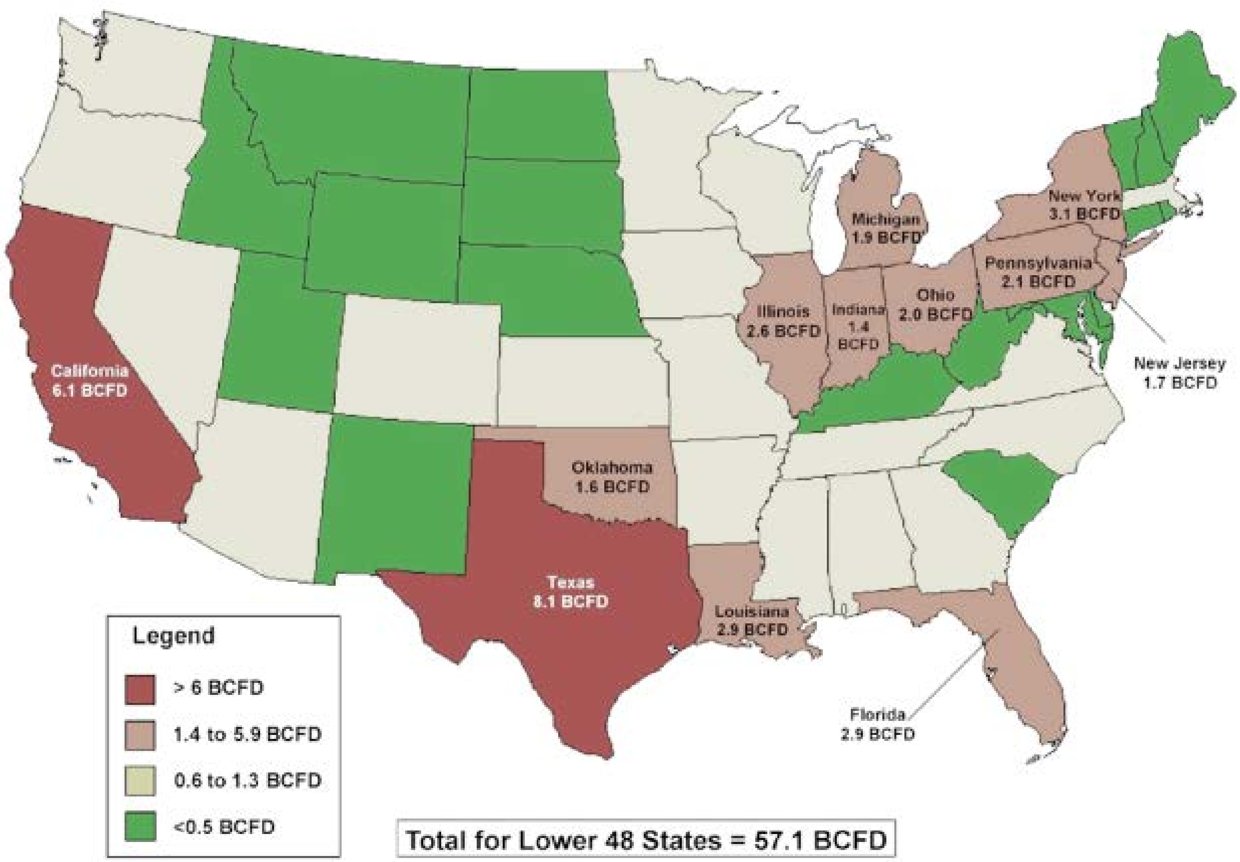
CONSUMPTION TOTAL PRIMARY GAS DEMAND

Similarly, primary natural gas demand is very concentrated, albeit not as concentrated as lower-48 gas production. This concentration in gas demand primarily occurs for two reasons, namely (1) gas consumption is high in the areas where it is produced (*i.e.*, minimum transportation) and (2) gas consumption is high in the major population centers.

Figure 6-2 summarizes primary natural gas consumption by state. There are two states that have much higher consumption levels than all the other states, namely Texas and California, which together account for 25 percent of total U.S. gas consumption. While there is a significant reduction in the amount of consumption after these two states, there are nine states that have between 1.4 and 3.1 BCFD. The combination of these nine states and Texas and California represent 58 percent of total primary gas demand in the U.S. These 11 high consuming states can be broken down into two categories, namely (1) Texas, Louisiana and Oklahoma, which are all large gas producing and gas consuming states, and (2) the remaining eight states, which all tend to represent high population areas. As a point of perspective the first category represents about 22 percent of total U.S. primary gas demand, while the eight high population states represent about 46 percent.

With respect to the remaining 44 percent of natural gas consumption, it is spread across the remaining 37 states within the lower-48, with half these states having primary gas consumption levels above 0.5 BCFD and half having consumption levels less than 0.5 BCFD.

FIGURE 6-2: 2010 PRIMARY NATURAL GAS CONSUMPTION BY STATE



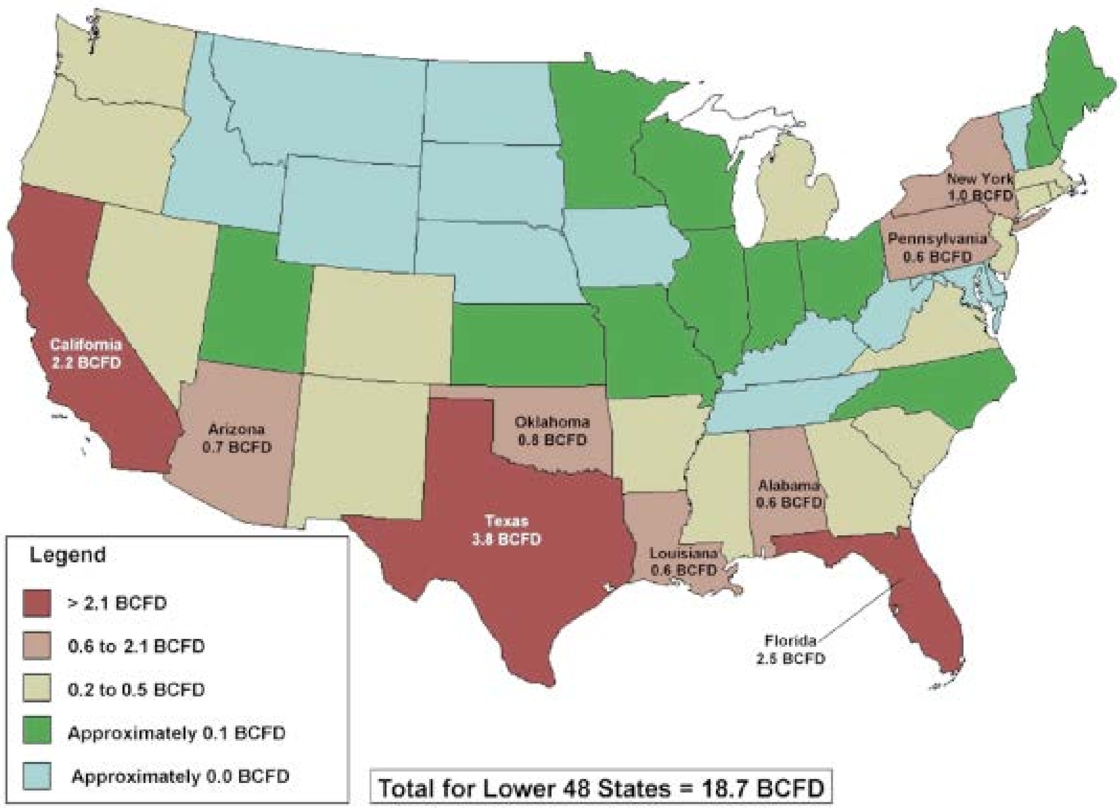
ELECTRIC POWER SECTOR

With respect to natural gas consumption within the power sector, it is very concentrated with just nine states accounting for about two-thirds of total electric sector gas consumption. In general, these states are further along in the process of optimizing the coordination between the gas and electric industries. With respect to coordination of the interface between the two industries in the remaining states, as gas consumption within in the electric sector increases over time, they likely will face a greater challenge in coordinating the interface between the two industries.

Figure 6-3 summarizes the use of natural gas within the power sector by state. Three states, namely Texas, Florida and California, use by far the greatest amount of gas within the electric sector, as these three states account for 45 percent of total power sector gas consumption. After these three states gas consumption on per state basis is reduced significantly, with the next six highest consuming states representing an additional 23 percent of total power sector gas consumption.

With respect to the remaining one-third of power sector gas demand it is spread across the remaining 39 states of the lower-48 as follows: (1) 15 states have consumption levels between 0.2 to 0.6 BCFD; and (2) another 11 states have consumption levels between 0.2 and 0.1 BCFD, while (3) the remaining 13 states hardly consume any gas within the power sector (*i.e.*, less than 0.1 BCFD).

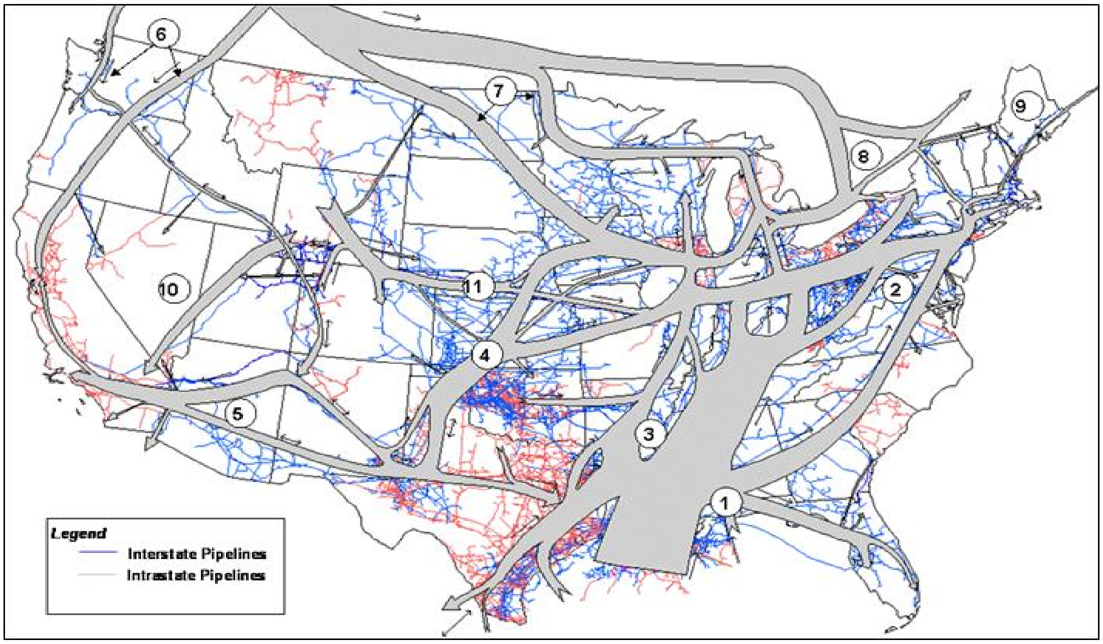
FIGURE 6-3: ELECTRIC POWER GAS CONSUMPTION BY LOWER-48 STATES



NATURAL GAS TRANSPORTATION

The combination of both natural gas production and consumption being concentrated within selected regions of the U.S. has required the U.S. natural gas industry to develop an extensive natural gas transportation network. The basic function of this network is to transport natural gas from production areas to markets, or sources to sinks. Furthermore, while the industry is changing, historically the backbone of this segment of the natural gas industry has been the long-haul transmission systems. In Chapter 3 it was noted that there were 38 major interstate transmission systems, plus another 72 non-major pipelines, and this was in addition to a large number of intrastate pipeline systems (*i.e.*, in total there are approximately 223 pipeline systems). These various pipeline systems are illustrated in the background of Figure 6-4. However, the key part of Figure 6-4 is a summary of the current pipeline corridors for the U.S. natural gas industry, which are illustrated in the foreground of Figure 6-4. These pipeline corridors provide the reader with a basic perspective of the movement of natural gas from major production areas to major market centers.

FIGURE 6-4: U.S. PIPELINE CORRIDORS



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division,
Gas Transportation Information System

ELECTRIC POWER INDUSTRY OVERVIEW

Not only are there significant differences in the fuel profiles for the various electric regions, but the fuel profiles for several regions have undergone significant change over the last two decades. In the material below both current fuel profiles for selected regions and major changes in regional fuel profiles are reviewed, while Appendix E presents the history for the fuel profiles for each region. Also, for this assessment regional fuel profiles are done on a census division basis, rather than for each of the NERC Regions. The primary reason for this approach is that consistent historical information for each of the current NERC regions is not available. Appendix D contains maps for the nine U.S. census divisions and the current NERC region, while Figure 6-5 presents the census regions and divisions.

FIGURE 6-5: CENSUS REGIONS AND DIVISIONS MAP

Corridors from the Southwest

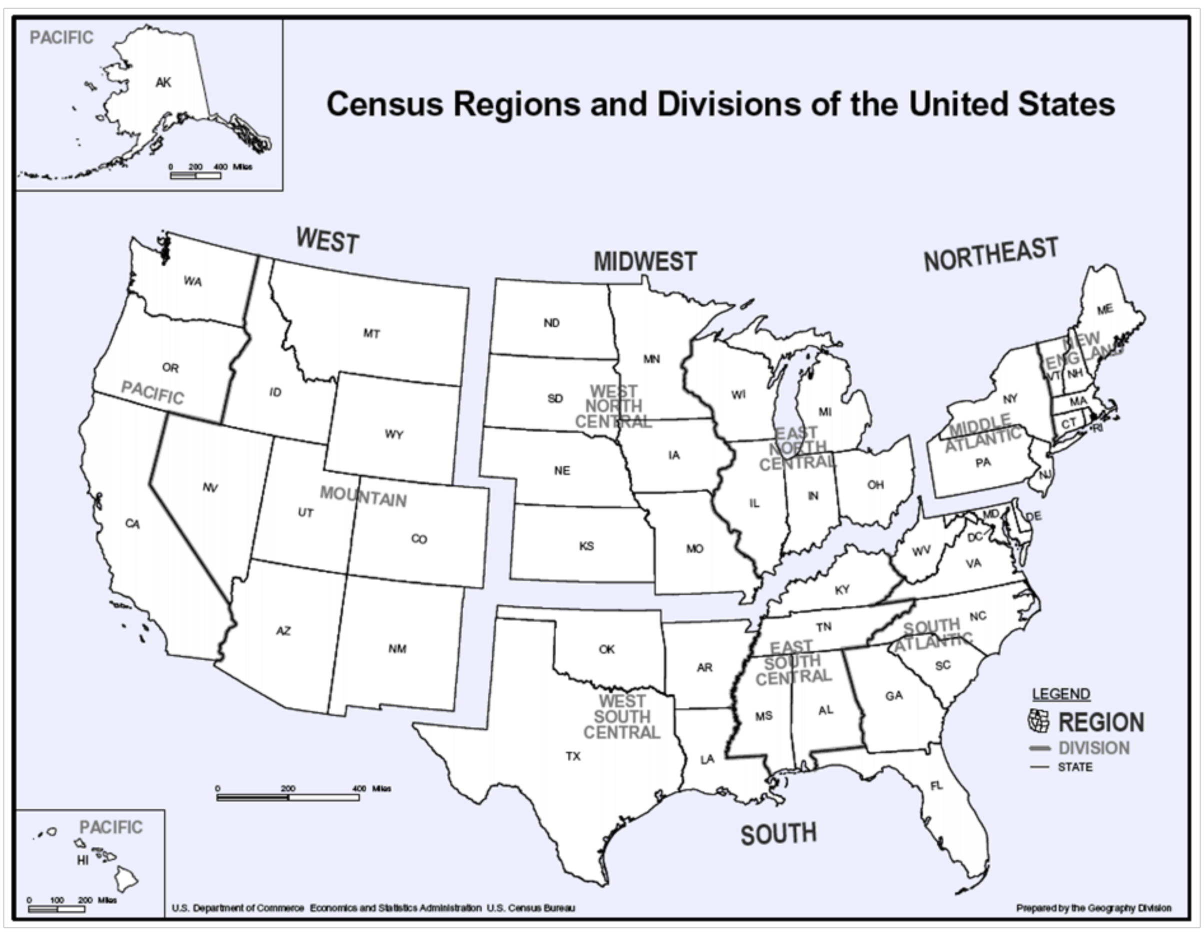
1. ***Southwest-Southeast***: from the area of East Texas, Louisiana, and the Gulf of Mexico, to the Southeastern States.
2. ***Southwest-Northeast:*** from the area of East Texas, Louisiana, and the Gulf of Mexico, to the U.S. Northeast (via the Southeast Region).
3. ***Southwest-Midwest:*** from the area of East Texas, Louisiana, and the Gulf of Mexico, and Arkansas to the Midwest.
4. ***Southwest Panhandle-Midwest***: from the area of southwestern Texas, the Texas and Oklahoma panhandles, western Arkansas, and southwestern Kansas to the Midwest.
5. ***Southwest-Western:*** from the area of southwestern Texas (Permian Basin) and northern New Mexico (San Juan Basin) to the Western States, primarily California.

Corridors from Canada

6. ***Canada-Western:*** from the area of Western Canada to Western markets in the United States, principally California, Oregon, and Washington State.
7. ***Canada-Midwest:*** from the area of Western Canada to Midwestern markets in the United States.
8. ***Canada-Northeast:*** from the area of Western Canada to Northeastern markets in the United States
9. ***Eastern Offshore Canada-Northeast:*** from the area of offshore eastern Canada (Sable Island) to New England markets in the United States.

Corridors from the Rocky Mountain Area

10. ***Rocky Mountains-Western:*** from the Rocky Mountain area of Utah, Colorado, and Wyoming to the Western States, primarily Nevada and California with support for markets in Oregon and Washington.
11. ***Rocky Mountains-Midwest:*** from the Rocky Mountain area to the Midwest, including markets in Iowa, Missouri, and eastern Kansas.

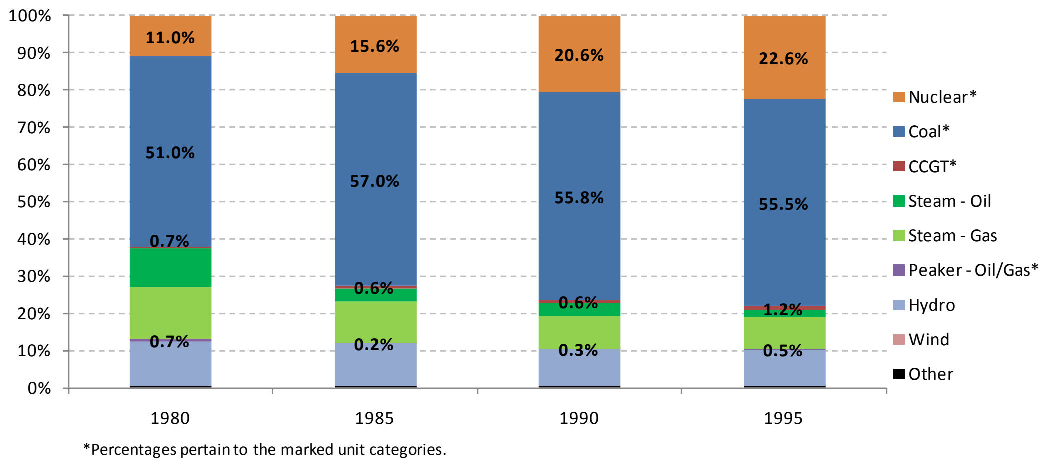


TOTAL U.S. FUEL PROFILE

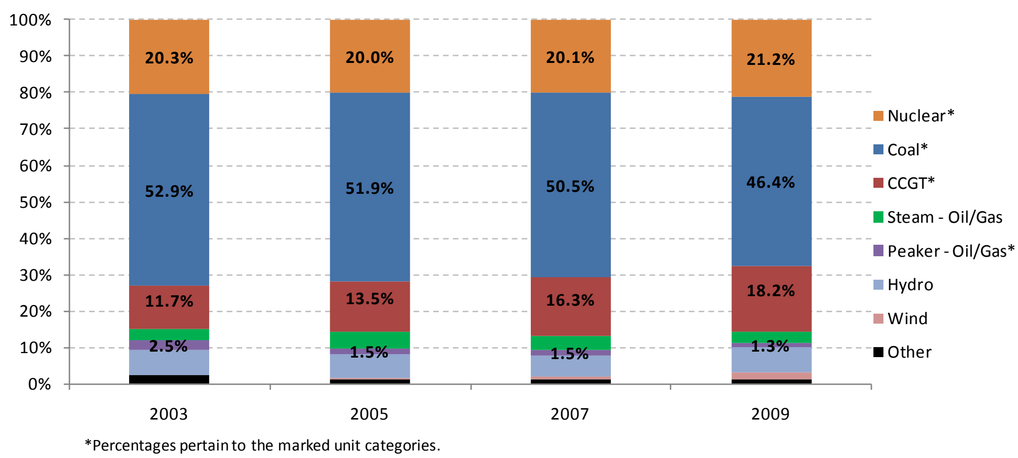
With respect to the total U.S., Figure 6-6 summarizes the history of the fuel profile for the entire U.S.[99] As illustrated, gas-fired generation for U.S. at a whole represented about 16 percent of total generation in 1980, but then steadily declined over approximately the next 15 years to about 10 percent of total generation. This decline was primarily the net effect of the Fuel Use Act and tremendous growth of nuclear generation during this era. Also, during the 1980s the relatively low cost coal-fired generation was still growing.

With the surge in additions of new gas-fired combined cycle capacity that occurred in the first part of the last decade, the contribution of gas-fired generation has increased rather steadily to about 22 percent. Also, by the end of 2009 nearly all forms of oil-fired generation had been displaced by the lower cost gas-fired generation. This is a trend that started in the 1990s, but was rather erratic during the 2000 to 2005 timeframe.

FIGURE 6-6: FUEL PROFILE FOR THE U.S. ELECTRIC POWER INDUSTRY HISTORICAL OVERVIEW



CURRENT OVERVIEW



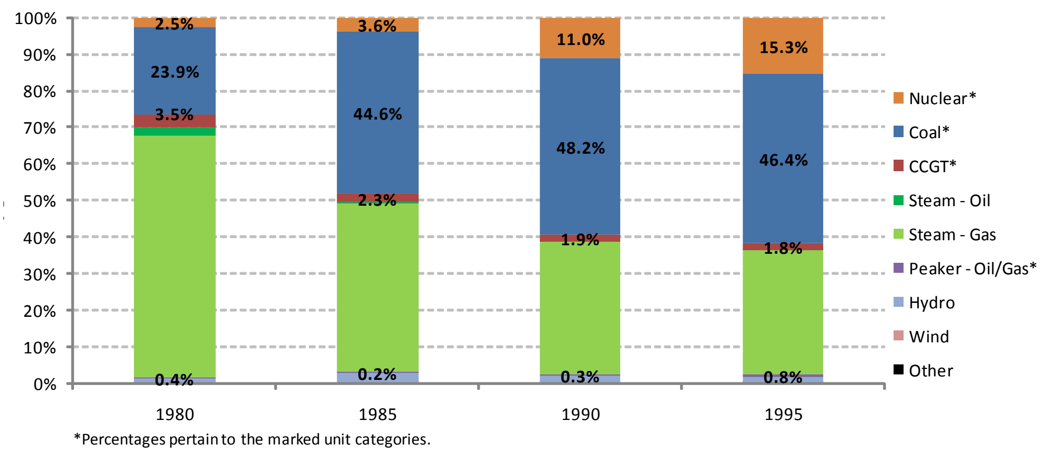
[99] Fuel profiles are based upon generation.

Range Of Fuel Profiles

Within the U.S. there is an enormous range in the contribution of gas-fired generation to an individual division's total generation. In case of the West South Central division, which includes ERCOT and much of the SPP, gas-fired generation always had been a large part of total generation. This is illustrated in Figure 6-7, where at present gas-fired generation accounts for about 40 percent of total generation. Also, noted in Figure 6-7 is that historically gas-fired generation had made even a large contribution, as in 1980 it represented about 70 percent of the generation mix. The decline over the decades was due to the combination of the growth in low cost (*i.e.*, at the time) coal-fired generation and nuclear generation.

This large contribution of gas-fired generation for the West South Central division needs to be compared and contrasted to the very small contribution that gas-fired generation makes in the West North Central (*i.e.*, primarily the MRO NERC region) and East North Central (*i.e.*, a combination of parts of the MRO and RFC NERC regions) divisions. Figure 6-8 summarizes the history for the load profile for the West North Central division.

Figure 6-7: West South Central Fuel Profile Historical Overview



Current Overview

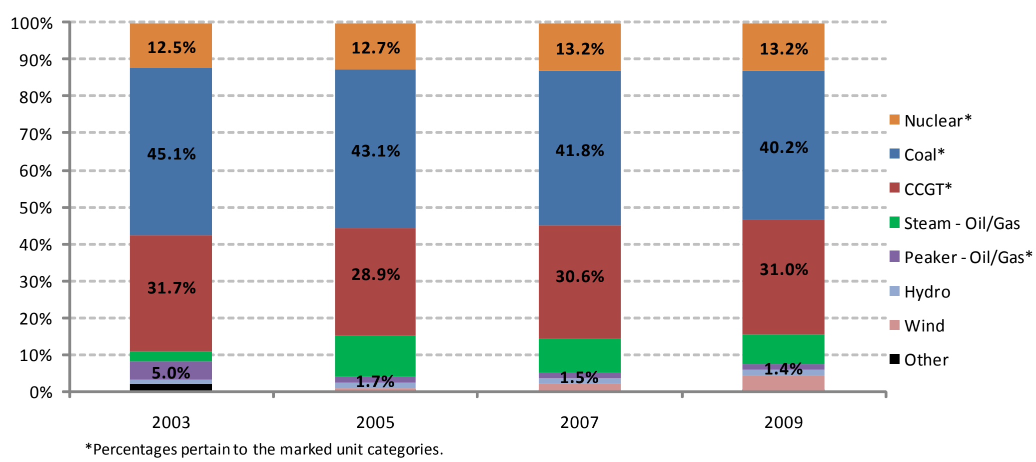
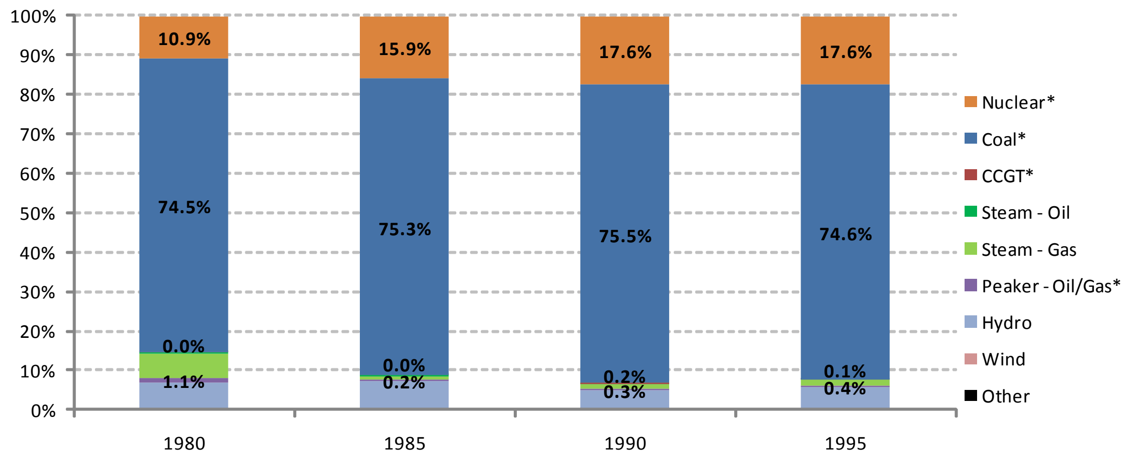
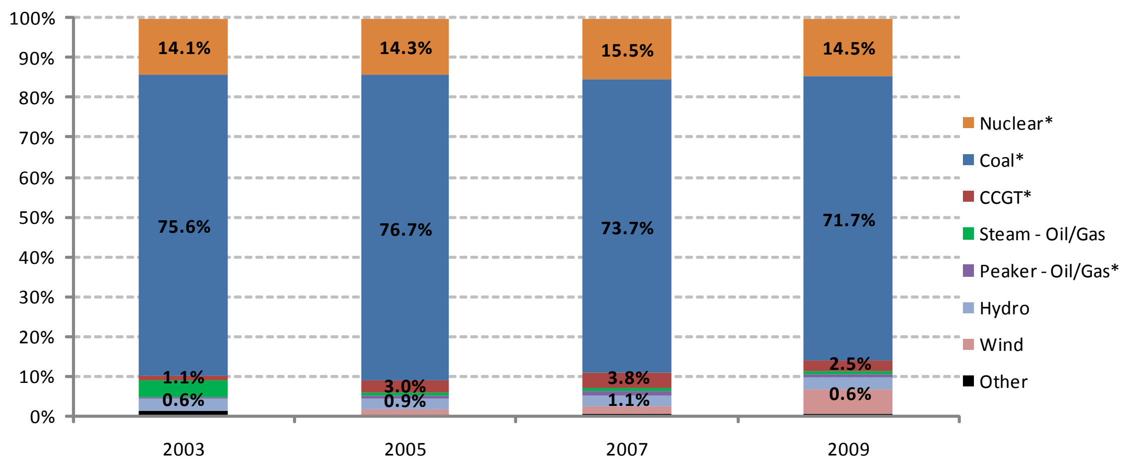


FIGURE 6-8: WEST NORTH CENTRAL FUEL PROFILE
HISTORICAL OVERVIEW



*Percentages pertain to the marked unit categories.

CURRENT OVERVIEW



*Percentages pertain to the marked unit categories.

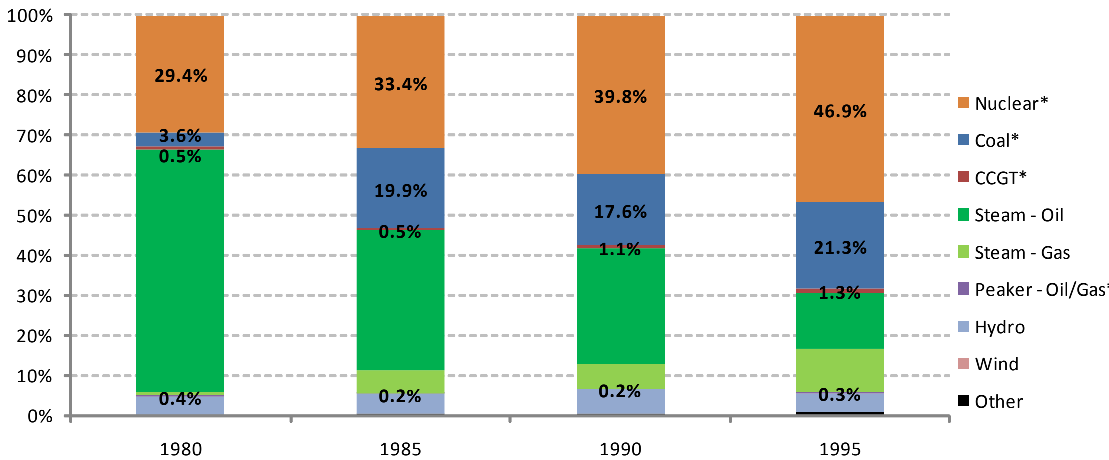
As illustrated throughout the history of the West North Central division, gas-fired generation has represented about five percent or less of the division's generation. In the East North Central division the contribution of gas-fired generation has been slightly less.

Some divisions have undergone significant changes in the contribution of gas-fired generation to the overall generation mix. The pace of this change in these divisions has heightened the need for coordination between the two industries. Probably the best example of such change for a divisional profile occurs in the New England division (*i.e.*, NEPOOL). Figure 6-9 summarizes the fuel profile for this division.

As illustrated in 1980, oil-fired generation dominated the fuel profile for this the NEPOOL division. However, the growth of both nuclear and coal-fired generation over the next 15 years steadily eroded the contribution of oil-fired steam generation within the division. Also, during this period there was some modest growth in gas-fired steam generation. However, the real surge in gas-fired generation occurred within this region occurred when the superior efficiency of the gas-fired combined cycle unit became recognized by the industry. The contribution of the gas-fired combined cycle unit increased sharply to about one-third of the division's generation mix in 2003 then continued to grow over the remainder of the decade to over 40 percent. Along the way the combined cycle units displaced both oil and gas-fired generation from the more traditional, but less efficient, steam generators within the division.

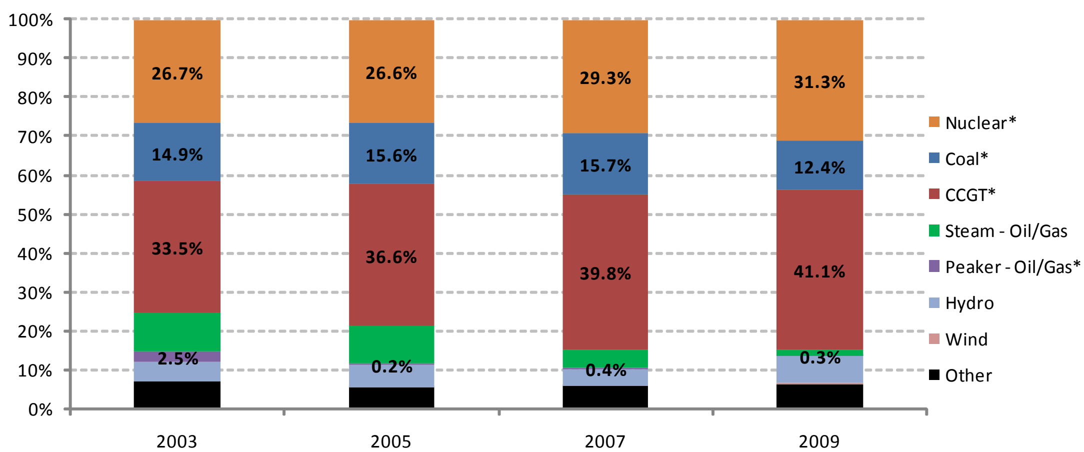
FIGURE 6-9: NEW ENGLAND FUEL PROFILE

HISTORICAL OVERVIEW



* Percentages pertain to the marked unit categories.

CURRENT OVERVIEW



* Percentages pertain to the marked unit categories,

Summary

While Appendix E provides the fuel profiles and projections for all NERC assessment areas, Figure 6-10 summarizes the history of just the contribution of gas-fired generation to each census division's total generation mix. One of the significant observations to be taken from Figure 6-10 is the significant growth in gas-fired generation that has occurred in the last roughly 10 years for at least five of the divisions.

Figure 6-10: Contribution of Gas-Fired Generation to the Total Generation Mix[100]

Census Division	Contribution of Gas-Fired Generation to Total Generation Mix							
	1980	1985	1990	1995	2003	2005	2007	2009
New England	2%	6%	7%	12%	41%	43%	45%	43%
Mid-Atlantic	8%	8%	8%	10%	14%	20%	22%	23%
South Atlantic	5%	4%	4%	7%	13%	20%	21%	25%
East North Central	1%	0.3%	1%	1%	5%	5%	5%	4%
East South Central	4%	2%	2%	4%	9%	8%	12%	15%
West North Central	7%	1%	2%	2%	6%	5%	6%	4%
West South Central	70%	49%	38%	36%	39%	42%	41%	41%
Mountain	10%	4%	3%	4%	17%	19%	25%	25%
Pacific	19%	24%	18%	16%	30%	30%	34%	33%
Total	**16%**	**12%**	**10%**	**10%**	**16%**	**17%**	**22%**	**22%**

Observations

For both the natural gas and electric power industries there are significant differences with respect to the concentration of natural gas production, natural gas consumption and the contribution of gas-fired generation to overall generation mix within an area. These differences create an added complexity to interface between the two industries, and in some respects heighten the need to focus on coordination between the two industries. The latter is particularly true going forward as the U.S. becomes more dependent upon gas-fired generation, likely causing some areas to experience a change in generation mix similar to what happened within New England.

[100] Energy Ventures Analysis independent assessment

Chapter 7—The Gas and Electric Reliability Interface

Since 1988 the electric sector has gone from the smallest consuming sector for the natural gas industry to the largest consuming sector.[101] In addition, going forward the electric sector will be responsible for most of the growth in natural gas demand. The combination of this growth in gas demand within the electric sector and its changing status among the gas consuming sectors has increased significantly the interdependences of the two industries, and caused many within both industries to focus more sharply on the interface between the two industries. A key element of this focus on the interface between the two industries is the need for increased coordination between the two industries, particularly at a regional level.

Pipeline deliverability can impact electrical system reliability in several ways. A physical disruption to a pipeline, or to a compressor station, can interrupt the flow of gas or reduce pressure to multiple electric generating units. At times of peak loading on the gas pipeline system, interruptible customers may be curtailed so that the pipeline may fulfill its contractual obligations to firm customers. As noted, firm customers usually contract up to 100 percent of the capacity in a pipeline, since pipelines do not build capacity to serve interruptible customers.

Historically, pipelines have built capacity to meet a winter peak demand resulting in underutilized capacity in the spring, summer and fall months. Some electrical generators have made business decisions to purchase interruptible gas delivery service. Pipeline delivery service tariffs for firm service typically contain a fixed monthly charge for reserving capacity that is not recovered from the electric marketplace for the low capacity factor operation typically seen by combustion turbine generation in peaking service. Thus, it is economically infeasible for a peaking generator to make capacity reservation payments for firm service that it cannot recover from its sales of electricity. If such a generator served by interruptible transportation has no alternative source of fuel, then that generating capacity could be unavailable to the electric grid at peak times.

Electrical systems also have the ability to adversely impact pipeline reliability. The sudden loss of a large generator can cause numerous smaller, gas-fired combustion turbines to be started in a short period of time, assuming capacity is there or other generators are available. This sudden demand may cause pipeline pressure drops that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric motor-driven gas compressor stations.

COMPARISON OF PIPELINE AND ELECTRICAL SYSTEM PLANNING

Many similarities exist between gas pipeline planning and operations and electrical transmission system planning and operations, but significant differences exist as well. These differences occur because the transmission system owner has less control over the size or location of the electrical loads served by the

[101] The electric sector became the largest consuming sector for natural gas in 2007.

transmission system, or in the timing of the use of electricity by the ultimate customer. A pipeline, on the other hand, knows the exact location of the customers who have a firm right to transportation capacity, and has contracts in place that describe exactly how much firm transportation capacity each customer may call upon.

In general, the owners of electrical systems anticipate load growth, and plan, design, and construct a transmission system that meets specific NERC Reliability Standards and that is capable of serving the forecast customer demands. The nature of the electrical grid, with numerous nodes where facilities are interconnected, and multiple parallel paths for electricity to flow, results in a flexible, robust electrical delivery system. Often, capability exists to accommodate growth in demand or to provide service to customer demands from alternative generation sources. NERC Reliability Standards dictate a layer of protection in transmission planning—utility planners must look at adding system backup, or robustness, to cover a scenario called a “single contingency situation” such as the failure of a transformer or other significant event that causes the outage of a transmission line or large generator. These single contingency scenarios are known as “N-1” (N minus one) conditions. The general philosophy is that no single failure of a piece of equipment connected to or comprising the transmission network should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (known as “N minus one minus one” scenarios or “N-1-1”). To recognize the specific regional attributes of its transmission grid, some operation and planning areas require additional planning standards. For example, some systems must be designed so that it can handle electric demand under extreme weather conditions (often referred to as a “90/10 load"), the outage of the two most critical generators, and/or limitations on the use of fossil fuel-fired peaking generation units. By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem on the bulk power system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

In general, pipelines also react to load growth. FERC will generally not authorize new pipeline capacity unless customers have already committed to it (Firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, results in new pipeline capacity closely matches the requirements of the new customers. If all of the pipeline’s firm customers use their full capability, little or no excess pipeline capacity will be available. This is a major difference between electric transmission and pipeline infrastructure construction. Electric transmission does not necessarily need to be approved by FERC, but transmission must be built to support speculative growth and socialized cost. Additionally, pipeline contingency planning standards, similar to transmission planning standards, do not exist. However, this does not mean that the pipeline system is not redundant. First, buried steel pipelines are inherently robust than and, therefore more resilient to extreme weather than transmission wires. Second, pipelines use series of side-by-side pipelines (called “loops”) that provide redundancy—even if one gets corroded, needs maintenance, or even loses integrity, the other loops can increase their pressure and make it up. The same is true of compressor stations.

Electrical systems are regulated by a combination of federal, state, and local authorities. FERC approves the rates for transmission service for wholesale electrical transactions. State or federal authorities usually approve electrical system expansion for major facilities—but it is not required for all projects. Retail electric rates are approved by state commissions for regulated utilities, local governments for municipal utilities, or consumer-owner boards for cooperative utilities.

Interstate gas pipelines are regulated by FERC, and approval for new major pipeline facilities is obtained from FERC. A significant amount of electric generation is served by LDCs and intrastate pipelines that are regulated at the state level. Pipeline tariffs for firm service, like electric transmission tariffs, are cost based. Interruptible gas service is provided on an as-available basis at volumetric rates.

From the perspective of the natural gas industry, it is much more difficult to meet the needs of electric customers than it is to meet the needs of its residential, commercial and industrial customers. There are three major reasons for this increased difficulty, namely:

- **High Point Loads:** Relative to other customers, electric units represents very large point loads.
- **High Pressure Loads:** Largely because of improvements in generation technology (*e.g.*, the aeroderivative combustion turbines) the pressure requirements for electric loads are much greater than those for other consumers.
- **Large Variation Loads**: Primarily because gas-fired generation is generally at the margin and is used primarily to meet intermediate and peaking electricity requirements, daily load requirements can be subject to significant variation, as a result of weather events or unplanned outages for other units.
- **Non-ratable takes**: Most pipelines are designed to provide uniform service over a 24-hour period. However, there is a limit on the amount of hourly flexibility that a pipeline can deliver (*i.e.,* burning 24 hours worth of gas with an 8 hour period). Furthermore, pipeline flexibility is greatly reduced should all firm customers take their full entitlement to service.

In the following material presented in this chapter each of these three areas and their impacts on the gas industry are examined in greater detail. This assessment is followed by a discussion of how the two industries have been able to coordinate to date and the need to increase this coordination in the future, particularly in regions which traditionally have not had large electric loads.

CHARACTERIZATION OF ELECTRIC UTILITY GAS LOADS

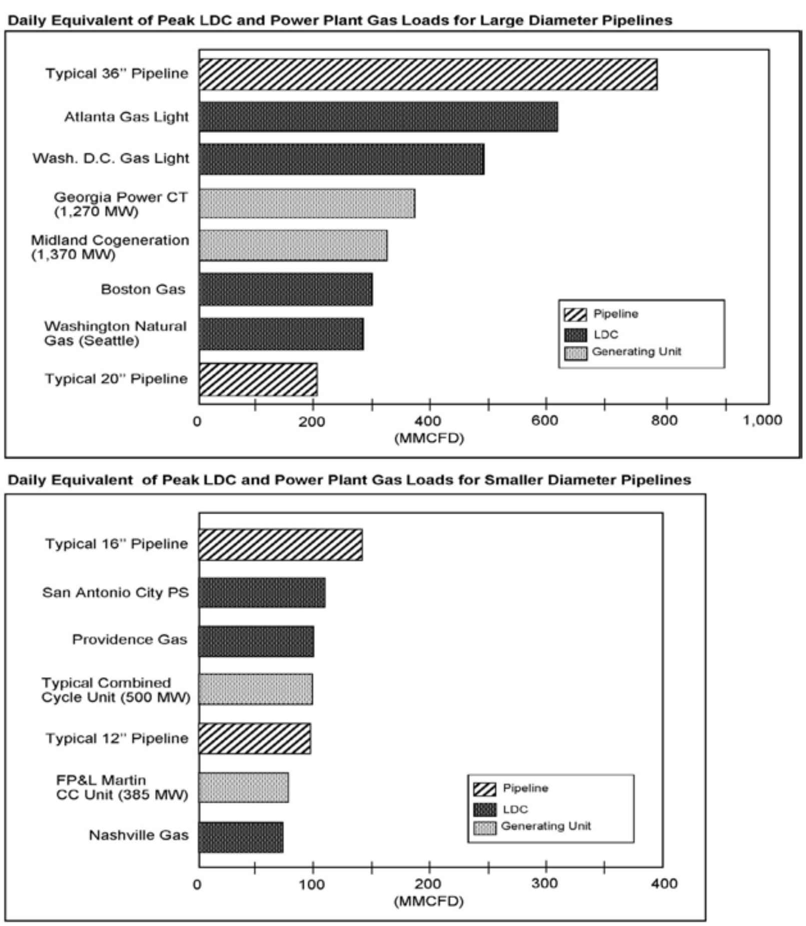
As noted above, from the perspective of the gas industry the three dominant characteristics of electric utility gas loads are large, high pressure, and highly variable. All three characteristics individually represent significant challenges for the natural gas industry and in particular, the pipeline segment of the gas industry.

LARGE LOAD POINTS

In order to provide some perspective of how large electric utility gas loads are relative to other gas loads and typical pipeline capabilities, Figure 7-1 compares and contrasts electric utility gas loads to those for several different LDCs and various diameter pipelines. Figure 7-1 is designed to illustrate how large some of the electric utility gas loads appear to a gas dispatcher relative to the LDC loads with which the gas industry, at least historically, is more familiar and which were the type of loads for which the interstate pipelines initially were designed to handle. The LDC loads are based upon the assumption that they are taken at a 70 percent load factor. Also, illustrated are typical daily design capacities for pipelines of differing diameter.

In addition, in order to make these load comparisons similar to what is observed by the gas dispatcher, hourly peak rates are assumed to exist over a 24-hour period, which allows the loads to be presented in the most common metric for the industry, namely millions of cubic feet per day (MMCFD). This approach is useful particularly in highlighting the loads for gas-fired peaking units for the power industry. Lastly, Figure 7-1 is divided into two graphics, with the upper graph highlighting the larger diameter pipelines and the lower graph highlighting some smaller diameter pipelines, which exist in some regions. The axes in the two graphs are different.

FIGURE 7-1: COMPARISON OF LDC, POWER PLANT LOADS AND PIPELINE CAPABILITIES



Source: EPRI, Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination (TR-101239), September 1992.

As illustrated, the electric utility loads are as large, or larger, than many of the LDC loads and, in some cases, can exceed the capabilities of the smaller diameter pipelines. In addition, for the most part, these electric utility loads occur at a single point, whereas almost all the LDC loads are served over multiple city gates.

Further perspective on the large size of the gas requirements for electric utility units is provided in Figure 7-2, which compares and contrasts gas loads for individual residential, commercial and industrial customers with that of typical peaking and combined cycle units for the power industry.

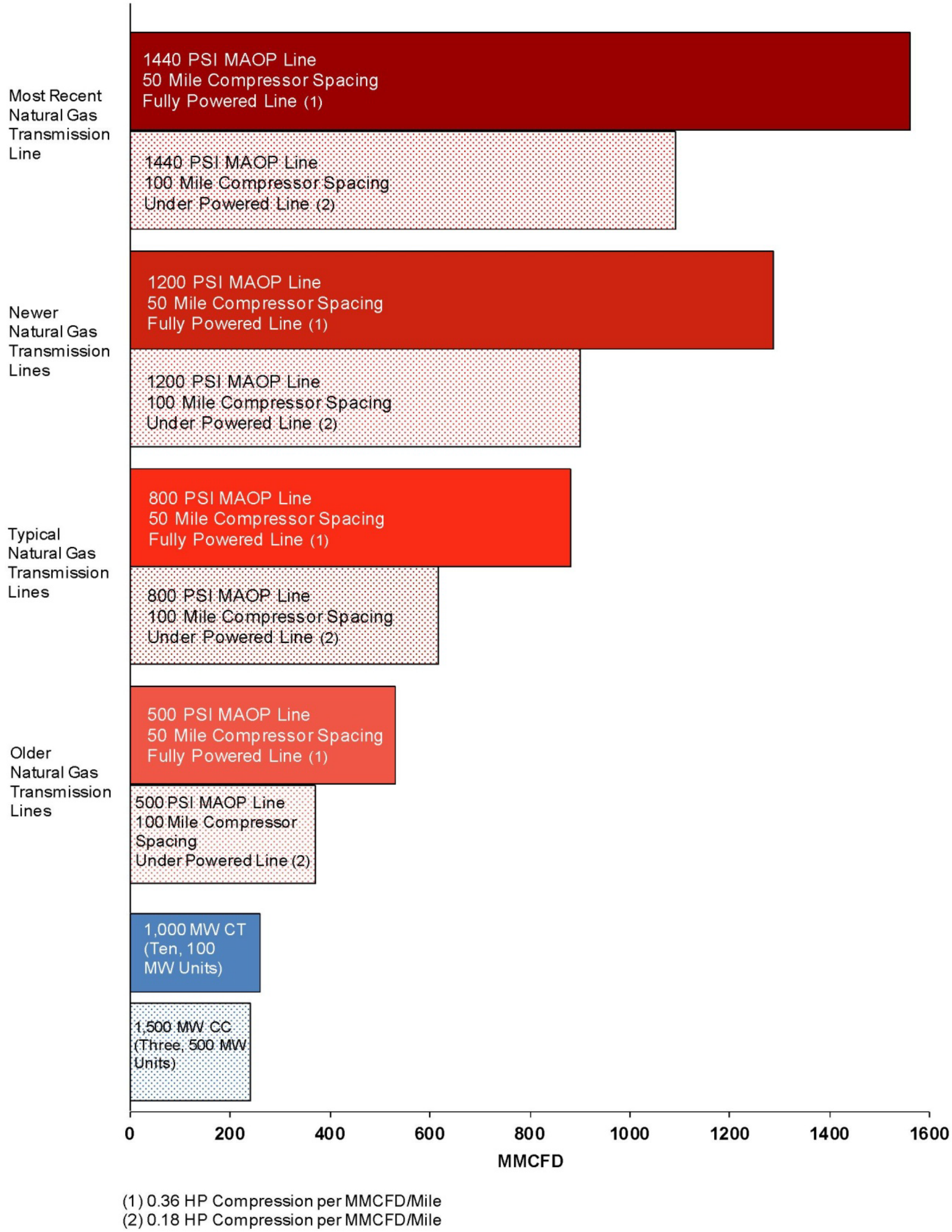
FIGURE 7-2: REPRESENTATIVE CUSTOMER GAS REQUIREMENTS

Relative Size (compared to residence-zero HDD)	Gas Requirement (CF per Hour)	Type of Customer/Application
0.05	4	Residence-summer day* (residential)
1	74	Residence-zero heating degree day (HDD)** (residential)
7	500	Major gas-heating shopping center in winter (commercial)
40	3,000	Major shopping center in summer w/gas cooling equipment (commercial)
2,700	200,000	Large urban food-processing plant (industrial)
20,000	1,500,000	100 MW combustion turbine (electric utility)
116,000	8,600,000	500 MW combined-cycle plant (electric utility)

**Well-insulated modern 2,500 square feet home with gas forced-air heat, gas hot water, and gas cooking.*
***Zero heating degree day refers to a day with no degrees below 65^{o}F.*

While Figures 7-1 and 7-2 provide a good perspective on the relative size of electric unit gas loads to the gas loads for other customers, they provide only a limited picture of the capabilities of the various pipelines. Figure 7-3 expands upon the pipeline comparison provided in Figure 7-1 and compares and contrasts electric gas loads to a range of pipeline alternatives under different pipeline operating conditions. However, in each case the pipeline scenarios are for a 36" diameter pipeline, which for most electric utilities would be the preferred alternative for receiving gas supplies, if the alternative exists within the region. Lastly, included in Figure 7-3 is a scenario that reflects the capabilities of newer pipelines being added to the interstate pipeline system, such as the Rockies Express Pipeline. These new pipelines, because of improvements in pipeline technology have a MAOP of 1,440 psi.

FIGURE 7-3: PIPELINE CAPABILITIES UNDER DIFFERENT OPERATING CONDITIONS (36" DIAMETER PIPELINES)



SOURCE: ENERGY VENTURES ANALYSIS, INC.

HIGH PRESSURE

Another challenging aspect for electric gas loads is the associated high pressure requirements. Modern combustion turbines have more stringent gas delivery requirements than older units. Higher required pressures and complex on-site gas cleanup and processing systems result in the potential for additional points of failure for the combustion turbine. Delivery pressures of 450 to 475 psi at the fuel skid are required for the most popular of the newer turbines—recent technology requires even higher pressures. Consistent fuel quality is necessary for the generator to meet operational and environmental requirements. These newer, larger, combustion turbine/combined cycle units are less tolerant to variations in gas quality and pressure than older units. Some combustion turbines require the gas to be heated prior to burning (hot gas units), thereby significantly increasing the start-up time from 10 minutes to 45 minutes.

LDCs, on the other hand, have relatively low pressure requirements for their loads at the city gates from about 800 psi to about 200 psi. In general, residential, commercial and industrial customers do not have high pressure requirements.

With respect to the power industry the pressure requirements for its gas loads have increased steadily for approximately the last 15 years as the power industry has transitioned from the less efficient steam generator technology to the more efficient combined cycle technology for gas-fired generation. Key to this transition, which also has impacted peaking units, is the shift to the aeroderivative combustion turbines. A key attribute of these aeroderivative units is their increased efficiency in converting fuel (*i.e.*, natural gas) into electricity, however in order to accomplish this phenomenon the fuel must be provided at higher pressures. This has resulted in an industry quest to increase steadily over the last decade the initial pressure for fuel for these turbines in order to obtain even more efficient units.[102] This basic trend towards higher pressure and thus, more efficient gas-fired units is summarized in Figure 7-4.

FIGURE 7-4: HISTORY OF AIR COMPRESSION IN TURBINES

Period	Compression Ratio	Compressed Air Pressure	Natural Gas Pressure Needs (approx.)	Heat Rate (BTU HHV/kWh)
Late 1970's	10.5:1	145 psi	200 psi	13,330
Mid 1990's	12.5:1	178 psi	250 psi	11,600
Late 1990's	15.5:1	220 psi	270 psi	10,860
Early 2000's	18.0:1	256 psi	325 psi	10,460
Current	28.0:1	400 psi	450-475 psi	9,750

While the MOAP for interstate pipelines[103] is greater than the pressure requirements for the newer electric utility units, the key dilemma is the loss of pipeline flexibility to deal with the unexpected, or abrupt, changes in load requirements. This occurs because gas moves relatively slow (*e.g.*, about 20

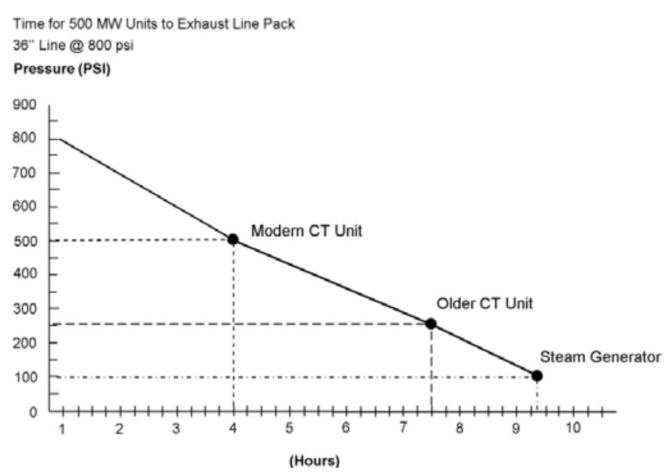
[102] The quest for greater turbine efficiency is limited not only by fuel pressure, but also temperature and the capability of materials (*i.e.*, metallurgy) to operate at higher pressure and temperature conditions.

[103] The MAOP for interstate pipelines range from (a) about 900 to 800 psi for some pipelines to (b) about 1,000 to 1,200 psi for other pipelines. The MAOP for the newest interstate pipelines can reach 1,440 psi.

mph). As a result, interstate transmission companies typically need to pack their pipelines in the evening, which results in increasing the pipeline pressure, in order to serve the required loads (*i.e.*, nominated loads) the next day. Then during the day as customer requirements are met the pressure within the pipeline system declines, with the process repeated for the next day. Colloquially, this is referred to as pack and draft.

The dilemma occurs when an unexpected event occurs (*e.g.*, weather or unplanned outages) that increases load requirements. Such an event causes the pipeline to reduce system pressure in order to meet the unexpected loads. Usually the pipeline encounters little difficulty in meeting such unexpected load changes from LDCs. However, the large increased loads associated with an unexpected generating unit coming online can exhaust the line pack rather quickly for a pipeline, as well as reduce the pressure in the pipeline to below the pressure requirements for generators. These conditions are possible even when gas is nominated 24 hours in advance and the unit has firm transportation. While some gas-fired units have contractual requirements for the delivery of gas at certain pressures, real-time conditions may not necessarily allow for the desired pressure to be reached in a given extreme situation. Figure 7-5 compares and contrasts how quickly a modern combustion turbine (CT) unit would draw down the line pack in a pipeline system[104] versus that for either a steam generator or an older CT unit. As illustrated, instead of taking about nine hours to exhaust system line pack in the case of a steam generator, it takes a modern CT only about four hours, or less than half the time. This time period can be further minimized should several units over-take gas simultaneously. Furthermore, this simplified example does not include meeting the minimum pressure requirement of the CT unit[105] or the potential for multiple units coming online.[106] Also, the potential for a modern CT unit to impact adversely system line pack is exacerbated by the rapid startup time of these units (*i.e.*, 10 to 20 minutes, with ramp down times just as fast).

FIGURE 7-5: NEW UNITS EXHAUST LINE PACK MUCH FASTER THAN OLDER UNITS



[104] The difference between the amount of gas contained in a pipeline system when operating near MAOP and the amount of gas contained in the system when operating near the minimum allowable pressure for the system is referred to as 'line pack', which can be used to meet surges in pipeline load requirements.

[105] The electric unit could use booster compression at its plant gate to offset the decline in pipeline pressure.

[106] One example of the multiple unit case is a sudden change in a regional weather pattern, which causes several utilities in the region to unexpectedly bring online additional gas-fired units.

Determining the exact level of line pack for pipelines is a relatively complicated task and depends upon a number of operational variables. Similarly, the time to exhaust a pipeline's line pack and place it in a critical operational condition requires a much more precise assessment than the simplified overview summarized in Figure 7-5. For a better appreciation of pipeline line pack and the potential for it being exhausted by modern electric units see Appendix F. Lastly, as a practical matter, pipelines have restructured their tariffs to the point where electric utilities should not consider relying on line pack to cover changes in their load requirements, however, it is still useful to understand the basic phenomenon and its physical limitations.

While the electric utilities continue to increase their pressure requirements in order to improve their overall fuel efficiency, from the pipeline's perspective, pressure is not free and increased pressure requirements can impair overall system flexibility or response capability. Hence, there is a tension between the two industries that needs to be carefully addressed and coordinated. Line pack is also not free, which drives up costs on firm service—parallel to ancillary services and determining how much reserve capacity is needed.

VARIATION IN LOADS

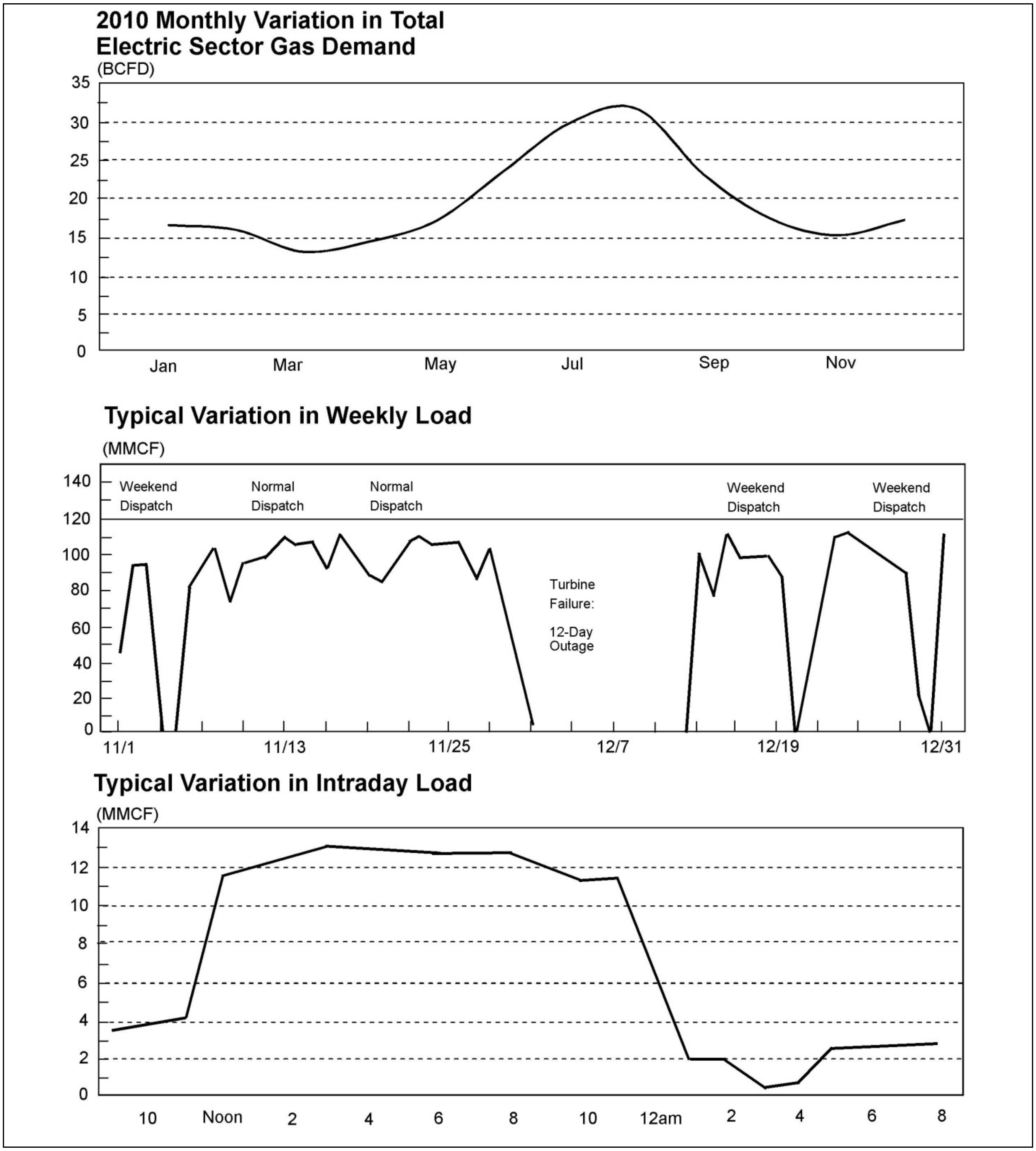
The other challenging aspect for electric gas loads is their variability. This occurs because gas-fired generation is used primarily to fulfill the intermediate and peaking segments of an electric utility's load profile, however in a few areas, such as Florida and California, gas-fired generation is also part of the base load segment of the load profile. The 'swing nature', or variation, in electric utility gas load profile on a seasonal basis and for weekly, as well as daily, load requirements is illustrated in Figure 7-6.

With respect to the seasonal variation in electric gas consumption, the upper graph illustrates that, in general, electric utility gas requirements peak during the summer season and that, on average, summer gas requirements can be double the consumption levels during the winter. However, there can be significant differences from this basic seasonal pattern for individual electric utilities. For example, in Florida a double peak exists with peak levels in both the summer and the winter, while there is a substantial decline in the spring and fall. In addition, the summer usually lasts for a longer duration.

More problematic to the gas industry is the variation in electric gas loads during the week and within a day (i.e., non ratable-take issues). The bottom graph in Figure 7-6 illustrates a typical pattern for both weekly gas load requirements and during an individual day. The latter is particularly difficult for pipelines to accommodate because they were initially designed for steady hourly load profiles (*i.e.*, 1/24 of the daily consumption requirement each hour).

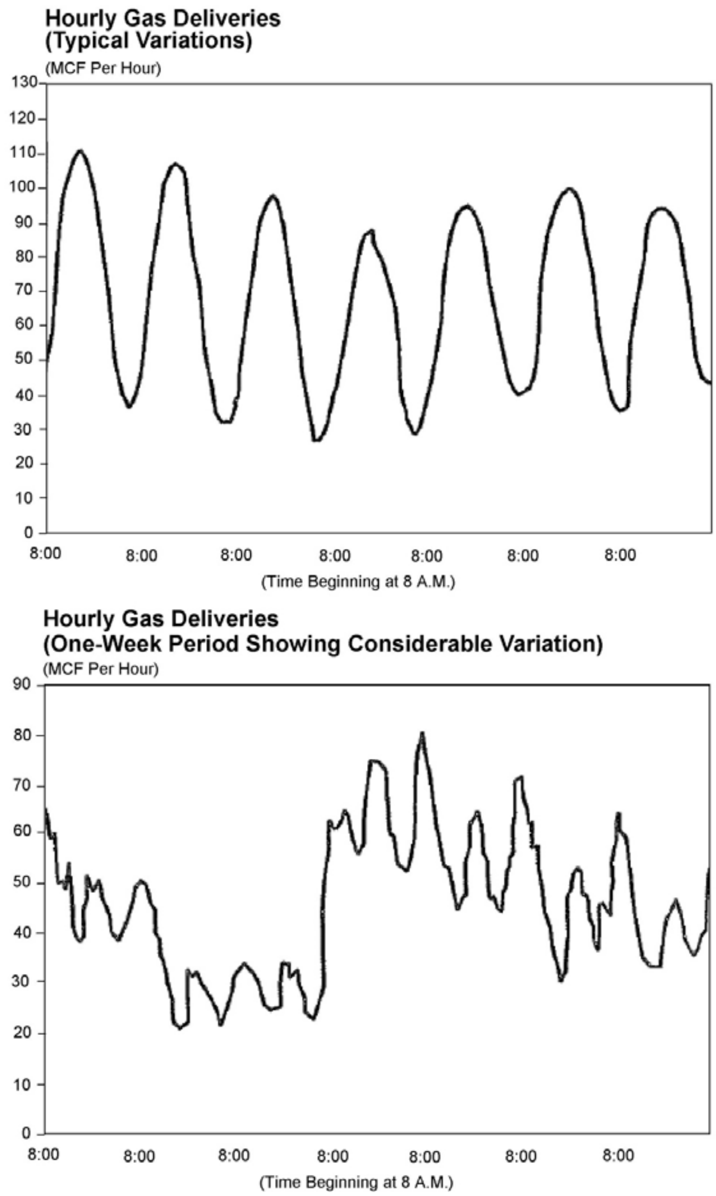
This variation, or swing nature, of electric gas loads is further demonstrated in Figure 7-7. The top graph illustrates a typical variation in hourly gas consumption under normal circumstances for a specific utility. While this represents a relatively predictable pattern, there are other instances where electric gas load requirements can be seen to defy any type of forecast and appear to be almost random. Such a case is illustrated in the lower graph in Figure 7-7.

FIGURE 7-6: SWING NATURE OF ELECTRIC UTILITY NATURAL GAS CONSUMPTION



Source: EPRI, *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination* (TR-101239), September 1992.

FIGURE 7-7: VARIATIONS IN HOURLY GAS DELIVERIES



Source: EPRI, Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination (TR-101239), September 1992.

WIND GENERATION

More recently another factor has evolved that causes variation in electric gas loads. This relatively new element is the requirement for gas-fired generation to balance the variable output profile for wind generation.[107] Wind generation has increased dramatically since about 2005, particularly in the west, Midwest, and Texas. Since the timing of when the wind will blow is dependent upon weather events and

[107] For most electric utilities gas-fired generation is considered the best alternative for balancing, or backing up, the variability in wind generation. For a few electric utilities hydro generation represents the best alternative.

somewhat normal diurnal patterns, the actual period of wind generation can be very difficult to predict. Similarly, it is equally difficult to predict the period when the wind will not blow, which is when additional gas-fired generation is required to fill-in, or balance, the electric utility's load profile. Gas turbines are almost an ideal technology to compensate for wind power variability. They can be quickly started (some gas turbines have cold startup times of less than 5 minutes) and can ramp up and ramp down their power levels faster than coal, steam, and nuclear plants can. This creates a new dimension to the swing nature of electric gas loads and can be a significant phenomenon in areas where wind generation is concentrated heavily (*e.g.*, Texas and North Dakota).

The strong growth in wind power and the lack of cost-effective storage solutions means systems will rely heavily on more flexible resources, such as gas turbines, to compensate wind power variability. Even in regions with significant amounts of hydropower (a better technology to compensate for wind power variability), gas turbines will still be required to backup wind power because environmental regulations limit the minimum and maximum amount of water a hydroelectric dam can release (termed run of river constraints).[108]

Gas turbines operate best at full-power steady state conditions where they are at their highest fuel and emissions efficiencies. Deviations away from this tuned set point result in significant inefficiencies (particularly with NO_x emissions) and increased operational costs.[109] NO_x emissions for the majority of the cases studied were not reduced and in some instances increased substantially. This is particularly important when considering pending environmental regulations and potential carbon legislation—not running at the fined tuned set point could trigger violations of environmental regulations.

DUAL-FUEL AND FUEL SWITCHING CAPABILITIES

Fuel switching enables a simple or combined cycle generating turbine to alternate between fuel sources, typically natural gas and some type of fuel oil. Fuel switching can be as simple as a control room operator pushing a button which automatically switches to oil, or as complicated as having to remove gas injectors and install oil injectors in every position around the boiler, a process that can take days rather than minutes.

It is common for units that switch to an alternate fuel type to experience a capacity derate, since normally each unit is designed to most efficiently burn a particular fuel.

The choice to perform fuel switching is primarily based on four factors: 1) reliability; 2) cost; 3) environmental restrictions; and 4) the availability of natural gas. Running the generating unit on alternate fuels, such as fuel oil, may cost up to twice as much on a MW basis with similar gains in pollutants. And environmental and air quality control restrictions, which vary by state, may limit the

[108] In recent events, Bonneville Power Administration (BPA) has called to curtail wind generation during periods of low demand due to hydroelectric generation limitations. http://205.254.135.24/todayinenergy/detail.cfm?id=1810

[109] Katzenstein and Apt's results are for wind + gas baseload plants. In other words, the turbine whose emissions are displaced is the same turbine that provides compensating power. Reference: Katzenstein, W., Apt, J. Air Emissions Due to Wind and Solar Power. Env. Sci. Technol., 2009, 43 (2), pp 253–258.

number of hours per year a generator is allowed to run on fuel oil. However, if a unit is needed for reliability, systems should be in place to ensure energy security—that is, reliability should be maintained regardless of other conditions.

Fuel switching raises a number of questions, such as: whether generators that have the capability to switch fuels should be required to maintain their alternate fuel equipment and stockpile an adequate supply of the alternate fuel, whether subsidies or incentives should be instituted to compensate for such requirements or to add fuel switching capabilities to those units that do not currently have it, and whether units that can switch fuels should be paid to do so in order to preserve gas supplies for residential consumers. These are issues that can be most fruitfully addressed in forums involving representatives of both the electric and natural gas industries operating in a given region, as well as the regulatory bodies overseeing them.

Fuel switching capability was a more desirable option in the past, when the relative prices of gas and oil fluctuated, making one or the other more economical at any given time. Given the decline in natural gas prices, this option has become less valuable.

However, given a rise in the amount of gas-fired generation, as well as projected into the future, a higher-degree of reliability is realized where fuel-switching is available. In essence, should a pipe disruption occur and loss of gas fuel imminent, generators with the ability to run on an alternate fuel, could withstand and "ride-through" the pipeline disruption without a significant impact to the bulk power system. With sufficient pipeline packing and the ability to quickly switch to an alternate fuel (and as well as sufficient fuel) these generators enhance the overall reliability of a given power system.

CONTRACTING PRACTICES

This variation in electric gas requirements presents challenges for both contracting for gas supplies and arranging for transportation to deliver the gas to a specific plant. Concerning the former, there has been a steady evolution in the contracting practices for gas supplies to include terms and conditions that provide for up to +100 percent swing capabilities in gas requirements. The inclusion of such terms is now relatively common, as is the cost for providing this swing service for gas supplies. In addition, electric utilities have learned to structure their portfolios of gas supply contracts to include base load contracts (*i.e.*, a specified quantity every day), limited swing supply contracts (*e.g.*, +30 percent) and large swing supply contracts (*e.g.*, +100 percent), in order to minimize the overall cost of the swing nature of their gas supply contracts. However, for regions just beginning to use significant amounts of gas-fired generation, they may need to learn from electric utilities in areas with more experience in order to optimize their gas supply contracting practices.

System operators and participants need to identify the additional costs incurred by generators when compensating for wind variability and electricity markets need to ensure adequate market mechanisms are present to allow gas generators to recover these costs. Using gas generators to mitigate wind power variability increases the variable costs of generators. For example, gas generators will have to spend more to obtain emissions permits to produce a MWh of electricity and spend more on maintenance because the maintenance schedule of a gas turbine depends on how much it cycled over its power range. In wholesale market areas, organized markets will need to ensure gas generators can recover these expenses. Compensating for wind power reduces the revenue stream of a gas generator because of the lost opportunity cost of operating at its maximum capacity. System operators will need to provide gas generators with a method to recover a portion of their lost opportunity costs in order to ensure enough gas generators are financially viable and will remain in the market to support the integration of wind power.[110]

While in the past there had been some gaming of the pipeline's swing capabilities, pipeline tariffs in most regions have evolved over the last decade to define specifically the limitations on variations from nominated gas requirements. Penalties that limit exceeding or undertaking nominated daily gas requirements (*i.e.,* Operational Flow Order (OFO) or balancing penalties) are in place in many areas. An OFO is a mechanism to protect the operational integrity of the pipeline. Pipeline operators may issue and implement system-wide or customer-specific OFOs in the event of high or low pipeline inventory. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage.

In addition, many pipelines have instituted new classes of premium services to accommodate the swing nature of some gas loads. The classic such service is 'no-notice' transportation, which is typically the most expensive transportation service offered by a pipeline. In addition, several pipelines have adopted transportation services earmarked particularly for the electric utility sector.

Much of the natural gas used by generators is purchased and transported on a portfolio basis which can include both firm and interruptible gas transportation. The regional availability of transportation service for natural gas is also a factor. Due to traditional supply arrangements and supply availability, firm gas supply cannot be obtained at any cost in some regions. Therefore, economics is not the sole reason a generator may not hold firm gas transportation.

Lastly, in most cases the key vehicle for meeting swing load requirements is natural gas storage, particularly salt dome storage with its multiple cycle capability. Exactly who owns and operates this storage capacity varies throughout the industry. In some instances, such as in Texas, the electric utility owns the storage facility and is thus capable of managing most or all of its swing requirements. In other instance the pipeline or gas trading firms control the storage capacity and charge a fee for providing swing services.

[110] https://wpweb2.tepper.cmu.edu/rlang/RenewElec/CEIC_White_Paper_on_Gas_Turbine_Research_for_Wind_Integration_3.pdf

COMMUNICATIONS

While improvements implemented during the course of the pipeline industries evolution are substantial and of significant benefit to the power industry, the creation of the deregulated gas industry has increased, to a degree, the difficulty of coordination between the power and gas industries. This occurs because almost every piece of information concerning operations in a deregulated market is considered to have some economic value and thus, is considered to be proprietary information.

A reoccurring theme expressed by the gas industry participants are concerns about communications between pipeline operators and entities (*i.e.,* Reliability Coordinators, Balancing Authorities, ISOs, and RTOs) other than the pipeline's contractual customers. Thus, the pipeline will communicate with the LDC serving a generator, or will communicate with the generator itself, but will not freely communicate with a Reliability Coordinator. This is due to the confidentiality of commercially sensitive business information and regulatory restrictions. The electric industry's concept of a Reliability Coordinator does not have a parallel entity in the pipeline industry. Information in the public domain, however, is generally shared between the pipeline operator and the independent electric operator.

This proprietary status on most operating information significantly increases the challenge of future coordination between the natural gas and power industries. However, this is not to say that this challenge cannot be overcome. Vital information needed for the reliable operation of the bulk power system should be shared with system operators from both industries. Examples of this include the sharing of maintenance issues (*e.g.,* the pipeline and the generators), new facilities perceived impact, load levels, dispatch principles and general patterns or forecasts for both industries.

In addition to the above, communications between two industries are hampered by the incompatibility between the traditional gas day, traditional electric day, and the market day (in market areas), which increases the difficulty of the gas industry providing the needed services to its largest consumer. The issues are further compounded by several different electric markets across several time zones.

GAS DAY

Within the gas industry the daily process for nominating gas volumes (*i.e.*, gas supplies and transportation), which is referred to as the 'gas day', traditionally has occurred from 9 a.m. CPT of the current day to 9 a.m. CPT of the next day.[111] While there are differences among the pipelines, in general, during this period the following key steps are accomplished:

- **Supplier Arrangements:** Shippers make the necessary arrangements with gas suppliers for required volumes for the next day's volumes (*e.g.*, 8 to 11:00).
- **Nominations**: Shippers submit nominations to a pipeline (*e.g.*, 11:30).
- **Confirmation**: Pipelines confirm nominations and reconcile any differences or inconsistencies (*e.g.*, 16:30.).

[111] All times of day referenced in this section are noted in Central Prevailing Time.

- **Scheduling:** Pipelines schedule gas quantities to flow at the start of next day (*e.g.*, 9:00 next day) and pack pipelines overnight as appropriate.

This entire process is done at a very granular level, which involves specific receipt and delivery meters. Also, the process involves intraday adjustments, if they can be accommodated. These intraday adjustments have very precise schedules and protocols. In some cases, "bumping rules" exist where firm priority nominations can bump other firm nominations of a lower priority until the end of the evening nominations cycle. Further, firm nominations can bump interruptible nominations until the end of the Intraday 1 cycle.[112]

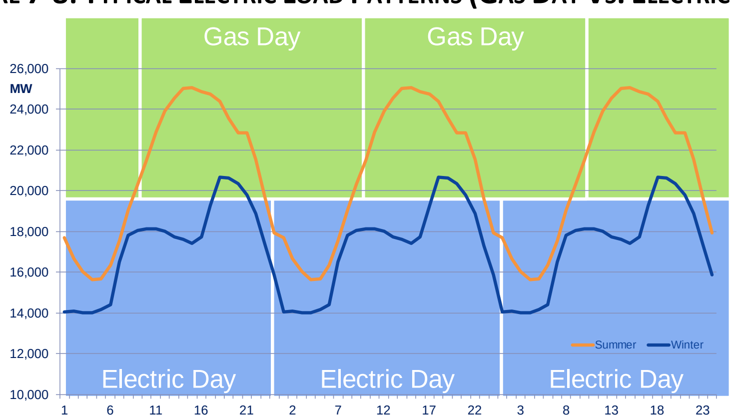
ELECTRIC DAY

For the power industry, the traditional planning day, or 'electric day', is from midnight to midnight. During this period electric utilities submit information to the power pool (or ISO/RTO, etc.), which then prepares projections of anticipated electric load for the entire power pool for the next day (*i.e.,* unit commitment). In addition, the power pool selects which electric power plants should be used to efficiently meet the load projection for the next day (*i.e.*, economic dispatch). As a result, power pool, utility, or ISO/RTO daily planning involves first determining the dispatch order of plants and second the amount of fuel that is likely to be consumed (in a regulated market area).

PLANNING GAP

While there are numerous similarities in the planning process between the gas and electric days, there are some areas of incompatibility. The major area of incompatibility is the difference in timing between the two days. For example, an electric day generally completes its planning for the next day usually by 6 p.m. of the current day. As shown in Figure 7-8, electric demands generally follow a sinusoidal daily pattern. However, the gas day begins the day during the morning "pick-up", and the electric day begins during the midnight "drop-off". The apparent phase shift observed during the two industry's operating/planning days creates some inherent challenges during the coordination, scheduling, and nomination processes.

FIGURE 7-8: TYPICAL ELECTRIC LOAD PATTERNS (GAS DAY VS. ELECTRIC DAY)

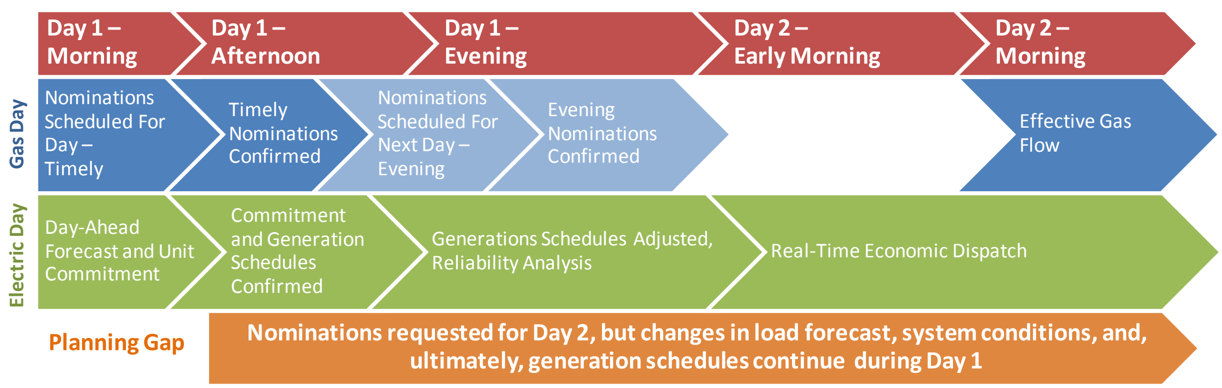


[112] Spectra Energy's bumping rules: https://link.spectraenergy.com/training/Advanced%20Nominations%20for%20TE%20AGT%20M&N%20US_files/frame.htm

While the completed electric utility plan identifies which electric units will run the next day, which in turn provides the basic information to project the next day's fuel consumption, the pipeline deadlines for nominations historically have been at 11:30 a.m. CPT of the current day (the day before the gas flows). Thus, there is a time gap, possibly up to eight or more hours, of incompatibility between the two traditional approaches to planning and scheduling.

The net result of this gap is that electric utility nominations, with their relatively large gas loads, are based upon estimates by the individual-fuel planners of each electric utility and not those actually contained in the power pool's final daily plan, as shown in Figure 7-9. This can result in significant differences between nominations and actual gas requirements—missing nomination under the timely cycle can have various disadvantages and/or penalties. Furthermore, sudden weather events can exacerbate these differences. When such differences occur pipelines may find it difficult to accommodate changes between nominations and actual load requirements. This can be accomplished by the early evening of the day-ahead (as shown in the lighter shade of blue), but as described in the next section, may be challenging. In addition, these differences often result in additional costs for the electric utilities, as they may be subject to number of imbalance penalties required under the pipeline tariffs.

FIGURE 7-9: SIMPLIFIED GAS AND ELECTRIC PLANNING AND OPERATIONS DAYS



RECENT CHANGES

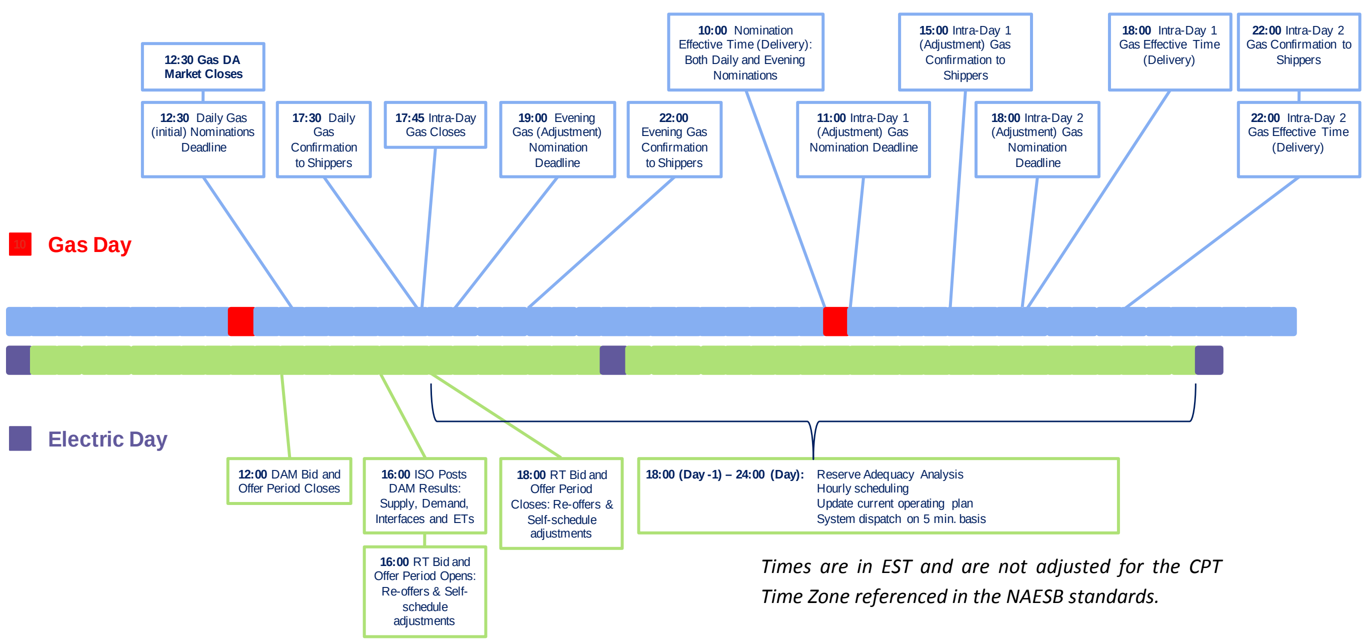
While there are regional nuances to the above portrayal of the gas day and the electric day, in general, within each region there is this basic incompatibility between the two planning days. In addition, while the above assesses the traditional gas and electric days, over the last decade each industry has made steps to accommodate the other – at least to a degree. For example, many, but not all, pipeline tariffs have been revised to include additional mechanisms for revising gas load nominations as shown in Figure 7-10. Historically, most pipelines only allowed for a single intraday adjustment to the original nomination of gas loads. However, over time, and largely to accommodate the power industry, many pipeline tariffs have revised their tariffs to allow for additional intraday adjustments to original nomination. For example, one major pipeline now allows three intraday adjustments to nomination. However, there are set times and protocols for each intraday adjustment and these adjustments will occur only if the pipeline is able to accommodate them. Similarly, some power pools are refining their planning and scheduling protocols so that information becomes available a few hours earlier in the traditional electric day. The latter can facilitate and aid in refined intraday adjustments.

FIGURE 7-10: NAESB GAS NOMINATION/CONFIRMATION CYCLES (CPT)

Nomination Cycle	Nomination Deadline for Shippers/Poolers	Point Operator Confirmation Deadline	Receipt of Final Scheduled Quantities by Shippers and Point Operators	Effective Flow Time
Intraday 1	10:00 a.m.	1:00 p.m.	2:00 p.m.	5:00 p.m. on the same gas day
Timely	11:30 a.m.	3:30 p.m.	4:30 p.m.	9:00 a.m. on the next gas day
Intraday 2	5:00 p.m.	8:00 p.m.	9:00 p.m.	9:00 p.m. on the same gas day
Evening	6:00 p.m.	9:00 p.m.	10:00 p.m.	9:00 a.m. on the next gas day

As shown in Figure 7-11, a detailed example from ISO-NE and pipeline service in the northeast, there are several points in the day when gas nominations can be requested. However, the 11:30 a.m CPT Timely nomination period is the only period when firm gas delivery is most certain. The Evening (5:00 p.m. CPT) nomination period is subject to interruptions depending on the pipeline capability on a specific day. Furthermore, the adjustment periods (Intraday 1 and Intraday 2) do not necessarily enhance gas delivery for the electric generation because confirmed gas will only flow past the peak hours (Intraday 1-5 p.m. CPT and Intraday 2- 9 p.m. CPT). However, it does add more flexibility to gas customers to accommodate changes in load and other generation forecasts (*i.e.,* variable generation) during off-peak hours.

FIGURE 7-11: EXAMPLE NOMINATION/SCHEDULING COORDINATION (ISO-NE)



Observations

The electric power industry has become the natural gas industry's biggest consumer and likely will account for most of the growth in natural gas demand over the next two decades. In addition, the industries have become highly dependent upon each other. In the case of the gas industry there has been an increased use in electric compressors, while the increased market share of gas-fired generation within the power industry has been significant and likely will continue to occur. These phenomena create interdependency between the two industries, particularly in certain regions, and overall requires an increased need for coordination, particularly during times of stress.

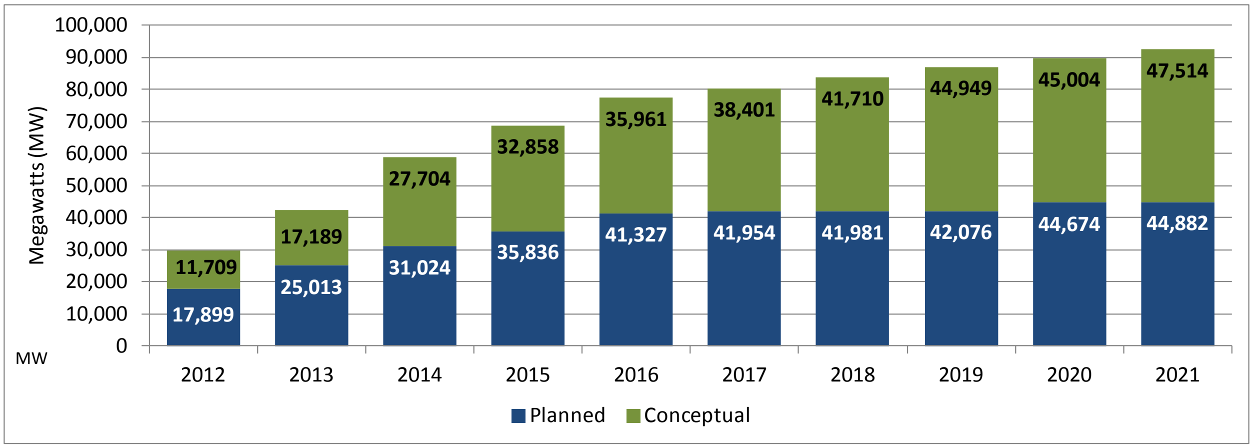
For example, in the event of an electricity brown out because of a severe weather event, power to run the electric compressors for a pipeline(s) might be reduced or cut off. This, in turn, could cause pressure in the very gas pipelines that supply fuel to the gas-fired electric units in the region to decline, causing gas-fired electric units in a given area to trip, particularly if the specific electric units do not have booster compression. Unlike transmission systems, a single failure in the gas pipeline could result in a loss of electric system capacity exceeding the most severe single contingency. Depending on the particular conditions, the failure of multiple compressor stations or a pipeline break could result in the loss of a significant amount of generation connected to the pipeline. The tripping of gas-fired units would likely lower overall power supply, significantly affecting reliability. The latter could create a downward spiral affecting additional electric compression, and thus, causing further pipeline pressure declines.[113]

Gas-pipeline disruptions (e.g., declines in production, pipeline failure) can propagate upstream through the rest of the gas delivery chain, ultimately disrupting delivery in areas outside a given electrical control area—or even outside an interconnection. The most recent example of this occurred during the February 2011 "Southwest Cold Snap".[114] Electrical disruptions in ERCOT resulted in gas curtailments in New Mexico, Arizona, and other parts of Texas outside of ERCOT. Well-head freeze-offs and rolling electric blackouts were principally the cause of gas curtailments outside of ERCOT.

Long-term growth of gas-fired generation should be considered in pipeline infrastructure planning. Over the next ten years, a significant amount of gas-fired generation is projected—45 GW of Planned and an additional 48 GW of Conceptual capacity (Figure 7-12).[115,116]

[113] This postulated example of the growing interdependencies of the two industries is not similar to the events that occurred in the southwest in February 2011.
[114] http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf
[115] Planned and Conceptual represent different resource categorizations depending on where these plans are in the current planning process, as defined in the 2011 Long-Term Reliability Assessment, http://www.nerc.com/files/2011%20LTRA_Final.pdf
[116] These plans do not fully account for additional capacity that may need to replace retiring coal-fired capacity due to pending EPA regulations.

FIGURE 7-12: 2011 LONG-TERM RELIABILITY ASSESSMENT GAS-FIRED CAPACITY PROJECTIONS



As described earlier in this chapter, pipeline capacity is expanded based on firm contracts. Despite the growth and future expansion of pipeline capacity described in Chapter 3 (Figure 3-3), it appears more pipeline capacity will need to be constructed. Much of the projected gas-fired capacity shown in Figure 7-12 does not have firm pipeline service, as this type of service is not expected to be needed for serving mid-range and peak demands. However, with environmental regulations potentially causing coal-fired base-load units to retire, gas-fired generation will likely be needed to serve more base-load demand. Therefore, gas-fired generation is not only expected to increase in on-peak capacity, but the energy profiles from gas-fired generation are expected to increase at larger growth rate. As a result, more natural gas will be demanded per day than as typically been observed. In essence, more pipeline capacity will be needed to serve the demands of the electric industry than what is currently and projected to be contracted for firm service.

Increased coordination between the two industries is needed. While progress has been made in the coordination between the two industries in certain regions,[117] for other regions there appears to be a steeper learning curve. The latter is particularly true for those regions which are just beginning to increase their use of gas-fired generation. For these regions it is realized that the gas/electric reliability interface presents a number of challenges, including the items presented in this chapter (*e.g.*, large, high pressure, point gas loads that are subject to considerable variation, and incompatibilities in planning and scheduling protocols). Nevertheless, progress has been made in other regions that are now more accustomed to the unique loads of power generators and this progress likely can be a benchmark for the remaining regions.

[117] One example is the New England region which formed its own gas/electric coordinating group. This group was able to formulate specific recommendations concerning better coordination of the gas/electric interface that were subsequently adopted (*i.e.*, see EPRI, *Natural Gas and Electric Industry Coordination in New England* (TR-102948), November 1993).

Chapter 8—Conclusions and Recommendations

2004 Conclusions and Recommendations

In the 2004 report[118] by the NERC Gas/Electricity Interdependency Task Force (GEITF), interdependencies and reliability considerations between the gas pipeline and electric generation operations and planning activities were identified. The task force concluded:

- Gas pipeline reliability can substantially impact electric generation.
- Electric system reliability can have an impact on gas pipeline operations.
- In general, pipeline and electric system operators do not understand each other's business very well.
- Pipeline planning and expansion are substantially different from the electric equivalent.
- Communications between pipeline operators and electric Reliability Coordinators are generally weak
- Pipeline tariffs for firm delivery service are not compatible with peaking generation economics in many electricity markets.
- Modern combustion turbines have stringent fuel delivery and fuel quality requirements.

The GEITF determined that interdependency between the gas pipeline and electric industries could lead to negative reliability impacts, and developed seven recommendations for future NERC action. The NERC Planning Committee approved these recommendations at its March 2004 meeting.

Recommendations

- Future natural gas storage facilities will not only have to satisfy the traditional demands for fuel supply reliability, but it will also have to satisfy the significant and expanding swings in demand for gas that can only be accommodated by high performance, multiple cycle natural gas storage facilities.

- Vital information needed for the reliable operation of the bulk power system should be shared with system operators from both industries—increased transparency in both markets is needed. Examples of this include the sharing of maintenance issues (*e.g.,* the pipeline and the generators), new facilities perceived impact, load levels, dispatch principles and general patterns or forecasts for both industries.

[118] http://www.nerc.com/docs/docs/pubs/Gas_Electricity_Interdependencies_and_Recommendations.pdf

- Communications between two industries are hampered by the incompatibility between the traditional gas day, traditional electric day, and the market day (in market areas), which increases the difficulty of the gas industry providing the needed services to its largest consumer. Contracting practices also make it difficult to plan the flexibility needed for both industries' reliable operation. A coordinated approach for engaging the two industries to come together and develop compromising solutions to address communication strategies, operational changes, and tariff changes is critical. FERC and the North American Energy Standards Board (NAESB) should develop strategies to harmonize the divergent views of the two industries.

- Vulnerabilities should be identified. Mitigating strategies should be incorporated into the planning and operation procedures for both industries. The electric industry should evaluate which generators may be most susceptible to pipeline disruptions (e.g., number of pipelines serving the generator, proximity to gas storage, and location relative to pipeline). The gas pipeline industry should consider electric system generation forecasts during the planning process. For operations, the sharing of real-time system information by both industries increases the ability for each to make informed decisions and reduce overall risk.

In the table below, the recommendations from the 2004 report are presented, along with a current status and any further action needed to address those recommendations. The majority of the recommendations are associated with implementing monitoring and tracking systems to increase communication and coordination between the electric and gas industry. While substantial improvements have been made since 2004, the electric industry is projecting an unprecedented fuel-mix change, incorporating more gas-fired generation into its resource portfolio. It is important for NERC and electric industry stakeholders to ensure technically sound solutions are in place to address and minimize gas-electric interdependency issues.

TABLE 8-1: RECOMMENDATIONS FROM 2004 GEITF REPORT, CURRENT STATUS, AND IDENTIFICATION OF FURTHER ACTION NEEDED

2004 Recommendation (Summary)	2011 Status	Further Action Needed
Long-Term and Seasonal Reliability Assessments should include a regional review of any fuel transportation infrastructure interruption that can adversely impact bulk power system reliability.	• Included in Long-Term and Seasonal Assessment questionnaire[119] o Identifying plans to mitigate impacts o Review of operational strategies should significant impacts occur	• Develop a more comprehensive approach for requesting detailed information on pipeline status and contingency plans • Long-Term Reliability Assessment should include a dedicated fuel-supply analysis

[119] http://www.nerc.com/docs/pc/ras/2011LTRA_Letter_v5.doc, http://www.nerc.com/docs/pc/ras/2011-2012%20Winter%20Assessment%20Letter_v2%20_2_.pdf

NERC Reliability Coordinators or their delegates should develop regular, real-time communications with pipeline operators about disturbances that could adversely impact the reliability of both systems.	• Some ISOs/RTOs (*e.g.,* ISO-NE) have developed protocols and implemented routine, real-time communications with regional gas pipeline operators.	• The Operating and Planning Committees should consider support from experts in the gas pipeline industry to provide liaison services. • Recommendations to be included in Phase II
Gas pipeline outages that could have an adverse impact on reliability of the electric systems must be coordinated with the electric industry so that plans to mitigate any impacts may be developed.	• Some ISOs/RTOs (*e.g.,* ISO-NE) have already begun identifying and coordinating regional pipeline outages that could impact electric system reliability.	• NERC should identify coordination practices between each Reliability Coordinator and pipeline operator in their respective area. • Recommendations to be included in Phase II
NERC should develop a reliability standard relating fuel infrastructure reliability to resource adequacy.	• To date, neither a NERC Reliability Standard nor a Standard Authorization Request has been incorporated in the standards development process. • NERC Reliability Standards are prohibited from addressing resource adequacy issues.[120]	• NERC should continue to assess resource adequacy in its periodic reliability assessments
NERC should require analysis of fuel infrastructure contingencies that could adversely impact the reliability of the bulk power system in the NERC planning standards.	• Included in Long-Term and Seasonal Assessment questionnaires o Identifying plans to mitigate impacts o Review of operational strategies should significant impacts occur	• The NERC should request further information from studies and analysis of potential system impacts due to pipeline contingencies in the Long-Term Reliability Assessment. • Recommendations to be included in Phase II
NERC should establish a monitoring system that tracks fuel infrastructure contingencies that have, or could have an adverse impact on bulk power system reliability.	• To date, NERC has not established a tracking and monitoring system; however, reliability coordinator-level, utility-level, or pipeline specific systems may exist.	• NERC technical committees should reevaluate the need for a tracking and monitoring system.
NERC should, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.	• Some ISOs/RTOs (*e.g.,* ISO-NE) have already begun identifying and coordinating regional pipeline outages that could impact electric system reliability. • Liaison activities exist between with NERC and the National Gas Council, along with coordination through the Interstate Natural Gas Association of America and the Natural Gas Supply Association	• Continue to engage the electric and gas transportation industry through the course of developing seasonal, long-term and special reliability assessments.

[120] Section 215 of the Federal Power Act (FPA), [215(i)(2)]

Appendix A: Incidents That Shaped the Natural Gas Industry

WINTER OF 1976/1977

The event that exposed the shortages of natural gas that had developed for the interstate gas market during the early 1970s, because of misguided regulations, was the winter of 1976/1977. This was the coldest winter on record, since 1931 (*i.e.,* 14.3 percent colder than normal). In addition, it was cold for almost the entire winter with individual months being three to 30 percent colder than normal. November, 1976 and January, 1977 both set all-time monthly records. The sole exception was March, 1977 when the weather finally turned warmer than normal.

Because of the combination of (1) the shortages in gas supplies for the interstate market, but not the intrastate gas market, and (2) the surge in gas demand because of the cold winter, the interstate pipelines were unable to fulfill about 25 percent of firm demand. As a result, more than 4,000 manufacturing plants were idled because of the lack of gas, which caused a million workers to be laid off. In addition, schools were closed. The President, under the Emergency Natural Gas Act, was granted extraordinary powers to intervene in private sector decisions affecting gas supplies, which allowed the head of the Federal Power Commission to order an interstate pipeline or a distribution company to relinquish some of its gas supplies to another system whose customers were in worse conditions. In addition, the Emergency Natural Gas Act, which only lasted for a few months, authorized the use of 'non-Jones Act' shipping to deliver LNG and also allowed for 'emergency' purchases of intrastate gas supplies by interstate gas pipelines at prices above the existing regulated prices for natural gas and without federal oversight.

Finally in November 1978 Congress passed the Natural Gas Policy Act. As an aside, the winter of 1977/1978 also was very cold, as it was the second coldest winter on record (i.e., 13.2 percent colder than normal).

IMPACT OF THE WINTER OF 1989/1990

In December 1989, abnormally cold weather in both consuming and producing areas (a 'double freeze') shocked natural gas markets, as well as heating oil and propane markets. Wells froze, pipeline capacity was affected by the cold and demand for heating fuels was much higher than would have occurred with normal temperatures. As a result of this abnormal condition, the prices of all three fuels increased sharply in December 1989and there were some curtailments of natural gas use. The winter of 1989/1990 produced only a single severe cold spell and, as a result, produced a limited test for the natural gas industry. A long cold winter, such as the winter of 1976/1977, would have provided a more stern test of the revised markets.

While December 1989 was the coldest December ever recorded for the section of the country east of the Rockies, the weather in January was the warmest for that month in at least 60 years. Thus, the period of heavy demand for natural gas was highly concentrated within the month of December and does not represent a period of extended high demand.

The most crucial part of the winter weather for the natural gas industry was the 'double freeze', which resulted in simultaneous freezes in major population areas (i.e., the Northeast and Midwest) and in the Southwest producing areas. This resulted in a significant loss of natural gas supplies due to well freeze-offs during a high demand period of high. The 'double freeze' lasted for about a week, from December 21 through December 28, 1989.

While the period of frigid weather in the Southwest was limited, it was severe. Temperatures were 80 percent colder than normal, wind chill factors were down to -35^{o}F and ice flows were reported 12 miles offshore into the Gulf of Mexico. The impact on natural gas production was extensive. Condensate associated with natural gas production froze, which caused ice plugs and prevented natural gas wells from flowing. In addition, there were failures of instrument lines and dehydration equipment, and even freezing of oil lines necessary for casing head production. Furthermore, the weather conditions precluded repair personnel from getting to wells to install equipment to begin the thawing process. Areas of Kansas, Arkansas, Oklahoma, Texas and Louisiana were all affected. Conoco reported a loss of about 30 percent of its gas deliverability, ARCO reported a loss of about 25 percent of its production and Texaco lost 915 MMCFD. Others companies reported production losses up to 40 percent of their capability.

However, the natural gas industry was able to offset this temporary decline in wellhead supplies with record levels of storage withdrawals. Storage withdrawals in December were 729 BCF, which was approximately five percent above the prior record in January 1982. Part of the reason the natural gas industry was able to attain this level of performance from storage was that the industry had steadily increased its storage capacity by 25 percent since 1977.

Only four of the 23 major interstate pipelines were forced to curtail firm services (i.e., Transcontinental Gas Pipe Line [Transco], Texas Eastern, Arkla and Southern Natural Gas Pipeline [SONAT]). These curtailments of firm services were caused by the loss of gas supplies due to well freeze-ups rather than any transmission capacity constraints (SONAT was an exception), and were in addition to the curtailment of some, or all, interruptible transportation on the various pipelines.

Transco, a major pipeline to the Northeast, incurred the greatest amount of curtailment, with 48 to 50 percent of its firm services being curtailed during the December 23rd through 26th period. Transco was somewhat unique among the interstate pipelines in that 75 percent of its supplies were from the Gulf of Mexico (GoM) and south Texas (*i.e.*, the areas that were the most affected by well freeze-offs) and it had very little system storage. It appears that if the hard freeze in the Southwest had lasted one or two days longer, the operational integrity of some pipelines would have been in question.

In addition to the curtailments of firm services by pipelines, some producers curtailed supplies under firm contracts (e.g., due to well freeze-offs) even though firm transportation was available. Thus, direct supply contracts with producers did not preclude (force majeure) curtailment of gas supplies.

Electric utilities during December 1989 consumed 24 percent more natural gas than was consumed by this sector in December 1988. In addition, there were considerable regional differences in this relationship. For example, New England utilities consumed 97 percent less natural gas than a year earlier. The early curtailment of interruptible transportation in the Northeast forced the utilities in this region to switch to alternate fuels early in December. In contrast, the traditional gas-burning regions for utilities (i.e., the Southwest and Mid-Atlantic) had consumption increases ranging from 26 to 59 percent.

In general, Southern utilities were more affected by the frigid weather, which caused significant outages of capacity, than were utilities in other regions of the country. Two electric utility areas, in Texas and Florida, were forced to curtail firm electric service during December, albeit for short periods of time. Both of these regions were traditionally large gas-burning regions for electric utilities. Other southern utilities, such as Entergy, had forced outages of 30 percent of their oil/gas capacity, but were able to avoid curtailments because of their heavy use of interconnections with other utilities.

In the case of Texas, record demands, combined with unprecedented generating capacity outages, both due to the severe cold weather, required firm load curtailments by two utilities for a five-hour period and by another utility for a three-hour period. As conditions worsened, all utilities within the electric grid in Texas interrupted firm load simultaneously to arrest a decline in system frequency. In almost all cases, firm load curtailments were on a rotating 15-30 minute basis. At the most critical stage, over 10,000 MW of capacity was out of service due to weather-related problems, and an additional 1,300 MW of capacity was lost to deratings because of oil burning.

While there were curtailments of natural gas supplies due to well freeze-offs, these utilities were able to offset the loss by using storage gas and fuel displacement. Natural gas-fired generation within Texas accounted for 40 percent of total generation during December.

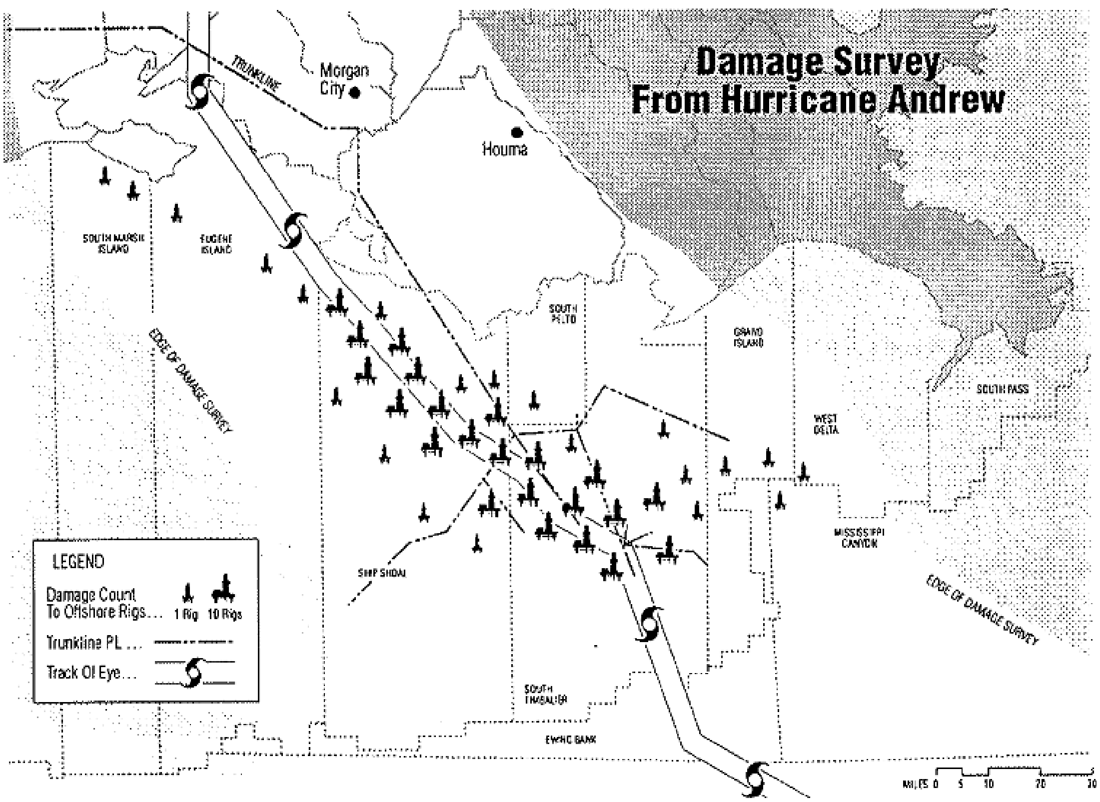
In the case of Florida, 11 utilities had to curtail electric load. In most cases the curtailments were for short periods of time on a rotating basis, although some lasted for three days. In Florida, peak was 20 percent above the installed capacity of all available units, which was the major cause of the electric curtailments. Natural gas supplies in Florida were via a single pipeline - Florida Gas Transmission -which experienced loss of supply like other interstate pipelines, but did not curtail service to any of its high priority (firm) customers. Electric utility gas supplies obviously were interrupted and during the critical period of interrupted services utilities switched to alternative fuels.

Causes of Curtailments: The loss of firm natural gas service was due to the loss of gas supplies during a period of high demand. The loss of supply was the result of the well freeze-offs rather than pipeline capacity constraints.

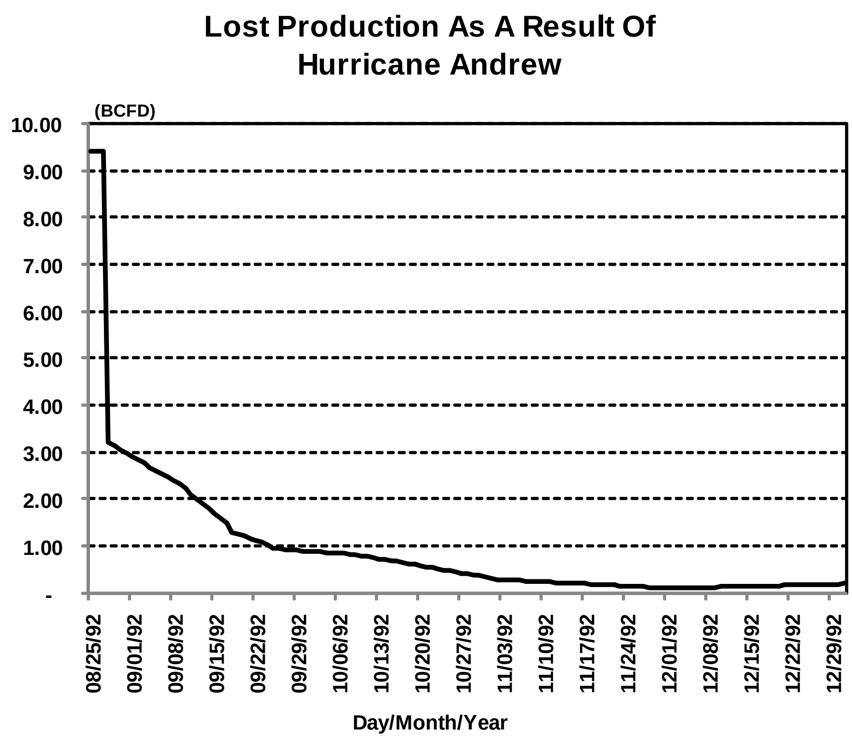
Electric Utilities: The winter of 1989/1990 reinforced the value of having fuel switching capability and either owning, or having access to, underground gas storage.

IMPACT OF HURRICANE ANDREW, AUGUST 1992

At the time of Hurricane Andrew the Gulf of Mexico had 3,852 platforms. Importantly, 800 of these platforms were designed to pre-1972 standards (i.e., to withstand 25-year storm conditions) and the remainder were designed to post-1972 standards (i.e., to withstand 100-year storm conditions). When Hurricane Andrew hit the Louisiana coast of the Gulf of Mexico on August 25th, approximately 2,000 platforms received hurricane force winds, of which 296 were damaged. In addition, 309 pipeline segments were damaged. The damage to the platforms included 112 platforms that sustained structural damage, 52 platforms with subsurface damage, 14 platforms that were toppled and four platforms that were leaning. The damaged platforms were concentrated in the Ship Shoal and South Timbalier areas with over 100 platforms damaged in each area (see map below).



The impact on natural gas production was significant, as illustrated in the graph below. Normal gas production from the Gulf of Mexico was about 13 BCFD, or about 26 percent of total U.S. production (i.e., excludes Canadian production). The initial impact was a reduction in gas production of approximately 9.4 BCFD as 37,500 industry employees including personnel from 700 platforms, were evacuated by midday on Tuesday, August 25th. Most of this lost production (*i.e.,* shut-in production) was recovered rapidly as crews were returned to the platforms on Thursday and Friday. Non-damaged and remote controlled platforms resumed production by Friday. The 296 damaged platforms resulted in 2.5 to 2.75 BCFD not being returned quickly to production. Many repairs occurred in the first few weeks. One month after Hurricane Andrew (i.e., September 25th) lost production had been reduced to approximately 0.9 BCFD, of which 0.1 BCFD of this lost production was not due directly to the hurricane, but rather due to a collision of a barge with Tenneco's West Cameron Platform Block 192. Lost production was reduced to 0.3 BCFD by November and 0.2 BCFD by the end of year. There were a few cases where production would be permanently lost, since it was not economic to repair or replace the damaged platforms - for example, one of the Unocal platforms (5 MMCFD).[121]



The damage to Trunkline's gathering platform for the Terrebone Offshore Pipeline System (TOPS) appears to have been the single incident with the greatest impact on lost gas production. Damage to this platform resulted in the loss of 0.8 BCFD. Furthermore, only 0.35 BCFD was recovered by September 9th, with the remainder scheduled to be recovered by November 1st after the completion of additional repairs. Unfortunately, after platform repairs were completed, Trunkline, on November 4th, experienced an explosion in the pipeline connecting to the platform which delayed full recovery of production. Trunkline was able to access some alternative sources of supply to offset this loss.

The total cost to repair all of the damaged platforms appears to have been at least $200 million. This additional burden on domestic exploration and production company budgets undoubtedly delayed the drilling of some new wells, but it is nearly impossible to quantify this impact on daily gas production.

[121] Although less severe than Hurricane Andrew, Hurricane Opal in October 1995 also forced significant curtailment of supplies from the Gulf of Mexico.

IMPACT OF THE SOUTWEST COLD WEATHER EVENT, FEBRUARY 2011 [122]

A NERC/FERC Task force examined data from numerous electric and gas entities to gauge the severity of shortfalls one commodity had on the other during the February event. Materials received from natural gas producers indicate that the rolling blackouts in ERCOT were a significant cause, from 29 to 27 percent respectively, of production shortfalls in the Permian and Fort Worth basins. For pipelines and LDCs, however, the effects of the rolling blackouts were negligible.[123]

Gas shortfalls caused problems for some generators in Texas, although not nearly to the extent as did direct weather-related causes such as equipment failure from below-freezing temperatures. In ERCOT, as detailed in the section of this report entitled "Causes of the Outages and Supply Disruptions," the outages and derates from inadequate gas supply during the cold weather event totaled 1,294 MW, compared to a peak net capacity reduction of 14,453 MW. While gas supply to Salt River Project and El Paso Electric was compromised due to problems at the Chevron Keystone Storage Facility, those utilities' generators failed for other reasons. However, during the 2003 cold weather event, there were significant gas curtailments to electric generators in Texas, which affected generating capacity. Gas curtailments also caused a lost of generating capacity in 1989, although to a lesser extent.

The task force was cognizant of the possibility that gas shortages may have been an insignificant factor in poor generator performance only because so many generators were forced offline for other reasons, and thus unable to take the gas (as was the case with Salt River Project and El Paso Electric). The task force attempted to answer the question of whether there would have been adequate gas supplies to ERCOT had this not been the case, by tallying and comparing the MWs forced offline, the amount of gas demand the generators would have imposed on suppliers had they been capable of running, and the capacity of the gas supply system at the time.

The task force determined that 5,256 MW of generation in ERCOT could have imposed demands on the gas supply system had the generating units not experienced trips, derates or failures to start. This number represents the total 5,556 MW of the 55 gas-fired generating units in ERCOT, reduced by 300 MW for those generating units connected to a single pipeline that was derated due to pressure or gas quality problems (making it unlikely the generating units could have received gas even if they had had no operational difficulties). Each unit was assumed to have a 9,000 btu/kWh heat rate. In the aggregate, these units would have added a maximum additional gas demand of approximately 1.1 Bcf per day.

Adding the additional hypothetical demand to the actual peak demand of 12.5 Bcf per day[124] would have imposed total demand on the system of 13.6 Bcf. Supply in January was running at 17.7 Bcf per

---

[122] http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

[123] An exception for LDCs is the surge effect experienced when electricity is restored after an outage, which places instant and simultaneous demand on gas equipment and systems. This is described in the section of this report entitled "The Event: Outages and Curtailments."

[124] The actual demand listed is a worst case scenario, because the calculation was derived by adding together the peak demand of each of the three major pipelines in Texas serving gas-fired generating units. A more realistic number would probably be demand of approximately 12 Bcf per day or less.

day. These volumes declined during the first week of February. On February 2, the worst day from the standpoint of ERCOT, supply declined to 16.35 Bcf per day. On February 4, when production volumes hit their lowest point for the week, supply declined to 14.08 Bcf per day.

A comparison of these supply and demand numbers shows that total demand (actual demand plus hypothetical demand) would still have been below the available supply during the February cold weather event, particularly so on the day rolling blackouts were implemented. The task force's analysis therefore indicates there would have been adequate gas to supply the generators in ERCOT that failed for mechanical reasons.[125] This conclusion was confirmed by knowledgeable industry observers, who were of the opinion that the Texas supply of gas would have been adequate had the generators not experienced weatherization problems.

FUEL SWITCHING

During the February event, 20 generating units in ERCOT attempted to switch fuels, with 15 managing it successfully.[126] (This echoed ERCOT's experience during the 2003 cold weather event, when a number of units that attempted to switch fuels were unable to do so, and those that did switch experienced derates of capacity[127]). SRP has nine units that are capable of switching, and EPE has three units capable of switching. None were asked to switch during the event, as the units failed for other reasons. In SPP, eight generating units have fuel switching capabilities; four attempted to switch during the event, with half of them being successful.

COMMUNICATIONS

Few examples of communication failures between gas and electric entities during the February 2011 event have come to light (although there were complaints of communication issues between shippers and pipelines). Nonetheless, the electric and gas industries might consider revisiting the GEITF 2005 recommendations to see if procedures should be developed for communications between pipelines and reliability coordinators.

WINTERIZATION

Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed.

---

[125] The excess gas was sold out of state, principally to the East, but had the generators in ERCOT been able to use it, they could have gotten it. All of these contracts were interruptible and had their prices pegged to indices; since gas prices rose modestly in the region during the event, the gas suppliers would have redirected the gas to Texas to take advantage of the higher prices, had the generators been able to accept it.

[126] A majority of the units that attempted to switch fuels but were unable to do so experienced a mechanical failure of some sort in the switching equipment, which could have been due to the cold temperatures, inadequate maintenance, lack of regular testing, or the infrequent use of the alternate fuel in normal operations.

[127] Public Utility Commission of Texas, *Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003* (May 19, 2003) at p. 17. The PUCT recommended that providing financial incentives for fuel oil inventories, to be maintained for use by dual-fueled generating units, should be considered.

The experiences of 1989 are instructive, particularly on the electric side. In that year, as in 2011, cold weather caused many generators to trip, derate, or fail to start. The PUCT investigated the occurrence and issued a number of recommendations aimed at improving winterization on the part of the generators. These recommendations were not mandatory, and over the course of time implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011.

On the gas side, producers experienced production declines in all of the recent prior cold weather events. While these declines rarely led to any significant curtailments, electric generators in 2003 did experience, as a result of gas shortages, widespread derates and in some cases outright unit failure. It is reasonable to assume from this pattern that the level of winterization put in place by producers is not capable of withstanding unusually cold temperatures.

While extreme cold weather events are obviously not as common in the Southwest as elsewhere, they do occur every few years. And when they do, the cost in terms of dollars and human hardship is considerable. The question of what to do about it is not an easy one to answer, as all preventative measures entail some cost. However, in many cases, the needed fixes would not be unduly expensive. Indeed, many utilities have already undertaken improvements in light of their experiences during the February event. This report makes a number of recommendations that the task force believes are both reasonable economically and which would substantially reduce the risk of blackouts and natural gas curtailments during the next extreme cold weather event that hits the Southwest.

Appendix B: Structure of the Natural Gas Industry

GAS TREATMENT SYSTEMS

Hydrocarbon Removal System

- **Absorption Process:** The absorption process was the primary process used for 25-30 years. In this process rich gas (gas containing a high percentage of heavier hydrocarbons) entered the bottom of a large vessel and flowed upwards. Lean oil (which has been stripped of the hydrocarbons) entered the top of the vessel. As gas and oil came in contact the heavier hydrocarbons were absorbed by the lean oil. The rich oil was then stripped of the hydrocarbons and recycled back to the vessel as lean oil. The amount of hydrocarbons that could be removed by this process was limited both economically and operationally, and therefore the remaining gas had a higher heating value.

- **Cryogenic Extraction Process:** The cryogenic extraction process has largely replaced the lean oil absorption process discussed above. Removal of hydrocarbons by the cryogenic process came about because of greater demand for feedstock hydrocarbons by the petrochemical industry. In a cryogenic process, natural gas is cooled through expanders. As gas is cooled, the heavier hydrocarbons liquefy and drop out of the process. This process, because of low temperature, removes the bulk of the ethane and other heavier hydrocarbons and can produce almost pure methane.

Acid Gas Removal Systems

- **Chemical Reaction Process:** Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are removed from the gas stream by chemical reaction with a material in a solution solvent. The reaction may be reversible or irreversible. In the reversible reactions, reactive material removes H_2S and/or CO_2 in the reactor. The reaction is then reversed by high temperature and/or low pressure in the stripper.

- **Absorption Process:** This process depends on physical absorption of H_2S and/or CO_2 in a solvent. The sour gas is absorbed in a vessel when the solvent is mixed with the gas and then the H_2S and CO_2 is stripped from the solvent. Since H_2S is poisonous, H_2S is normally further converted to elemental sulfur or burned in the atmosphere to form sulfur dioxide (SO_2). Environmental restrictions limit the amount of H_2S flaring that can be done.

- **Adsorption Process:** This process depends on physical attachments of the H_2S and/or CO_2 molecules to a material. Once the material is saturated, the acid gases are stripped from the material with steam and/or gas.

Water Removal Systems

- **Liquid Desiccant:** An absorbing liquid (glycol) is circulated through the natural gas in a large vessel and the water is absorbed by the liquid desiccant. This desiccant is then sent to a reboiler where it is heated and the water boiled off. The glycol is then returned to the vessel after cooling to absorb more water from the gas.

- **Dry Desiccant:** Gas is passed through a vessel containing a solid desiccant. This desiccant absorbs the water. When the desiccant becomes nearly saturated with water, it is desorbed by driving off the water with heat. Then the cycle is repeated.

- **Refrigeration:** Gas is cooled until all of the water vapor condenses. The water is removed with float controls and the cold dry gas is returned to the system through a heat exchanger to improve the cycle efficiency.

Measures Of Storage Capacity

There are four main measures of storage capacity:

- **Working Gas:** Working gas capacity is the total amount of gas that can be injected into a storage facility that will be available for delivery at a later date.

- **Base Gas:** Base gas, also known as cushion gas, is gas that must be permanently injected into storage in order to maintain adequate reservoir pressure required to maintain deliverability. In depleted fields, the base gas may include some native gas that was not produced. In some fields, base gas may be withdrawn in emergency situations.

- **Deliverability:** Deliverability is the total amount of gas that can be withdrawn from the storage field in one day at a given wellhead pressure. Since deliverability declines as the total volume of gas and reservoir pressure falls, storage providers will contract firm capacity for only a fraction of the peak deliverability.

- **Injection Rate:** The injection, or fill rate, is the rate at which gas can be added into storage in a single day. The maximum injection rate declines as storage volume and reservoir pressure increases.

Appendix C: Regional Production, Profiles, and Other Supply Information

FIGURE C-1: GULF COAST ONSHORE

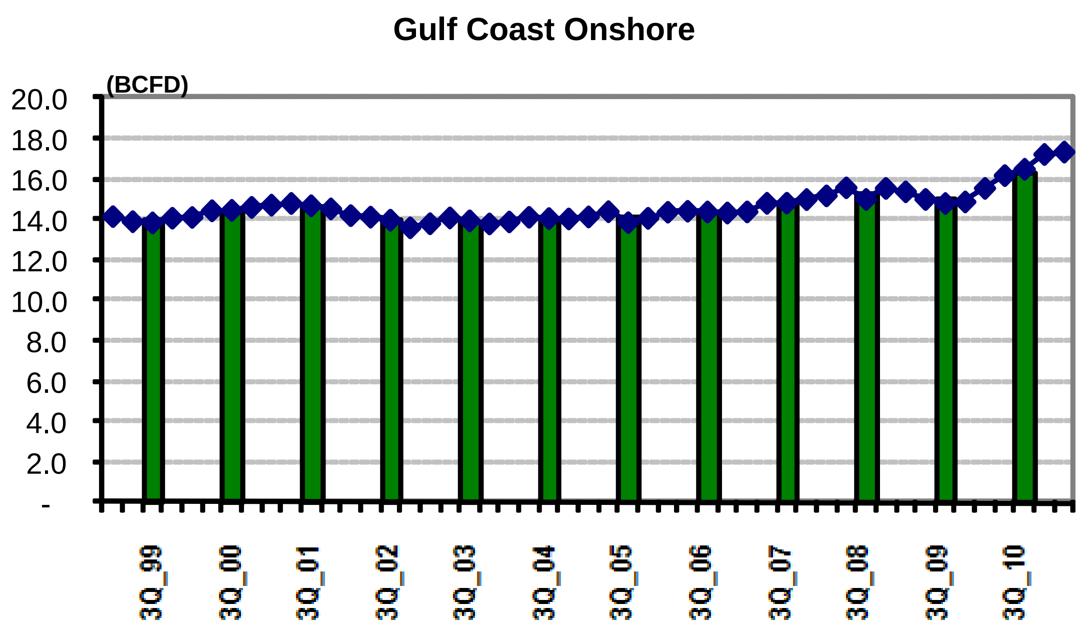


FIGURE C-2: MID-CONTINENT

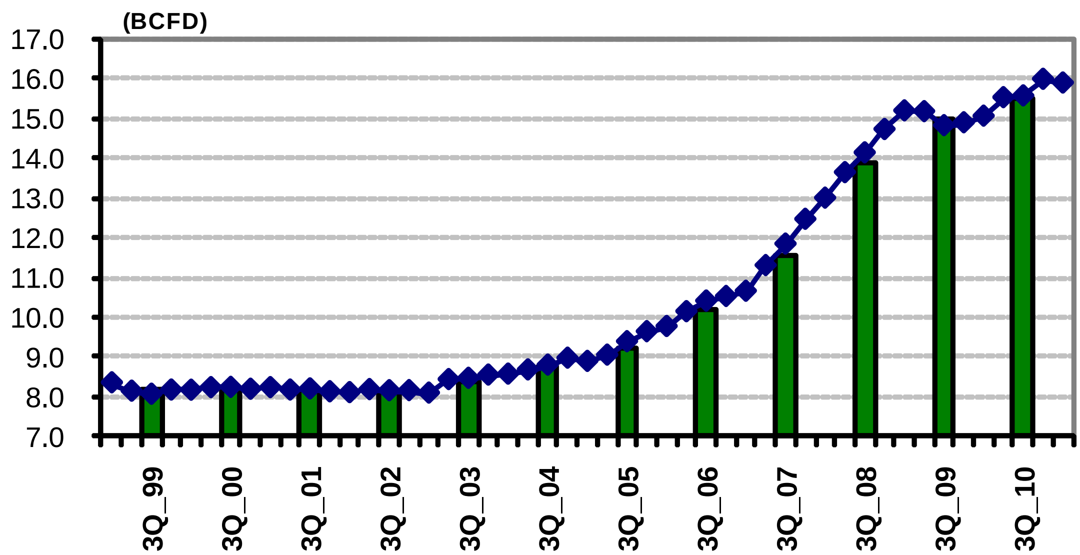


FIGURE C-3: PERMIAN BASIN

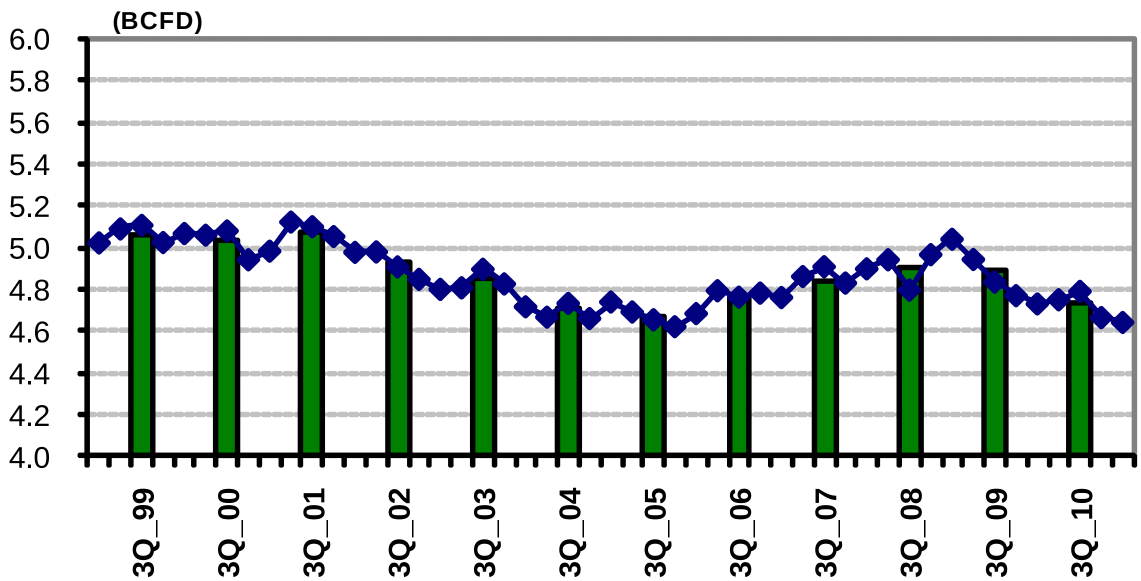


FIGURE C-4: GULF COAST OFFSHORE

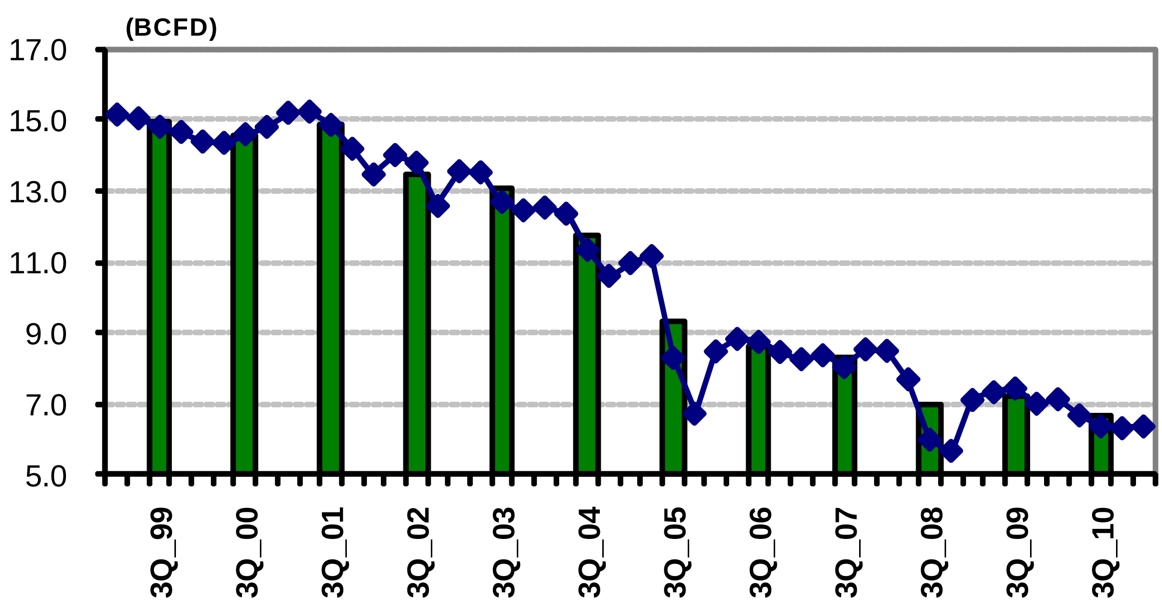


FIGURE C-5. SAN JUAN BASIN: TIGHT SAND AND COAL-BED METHANE

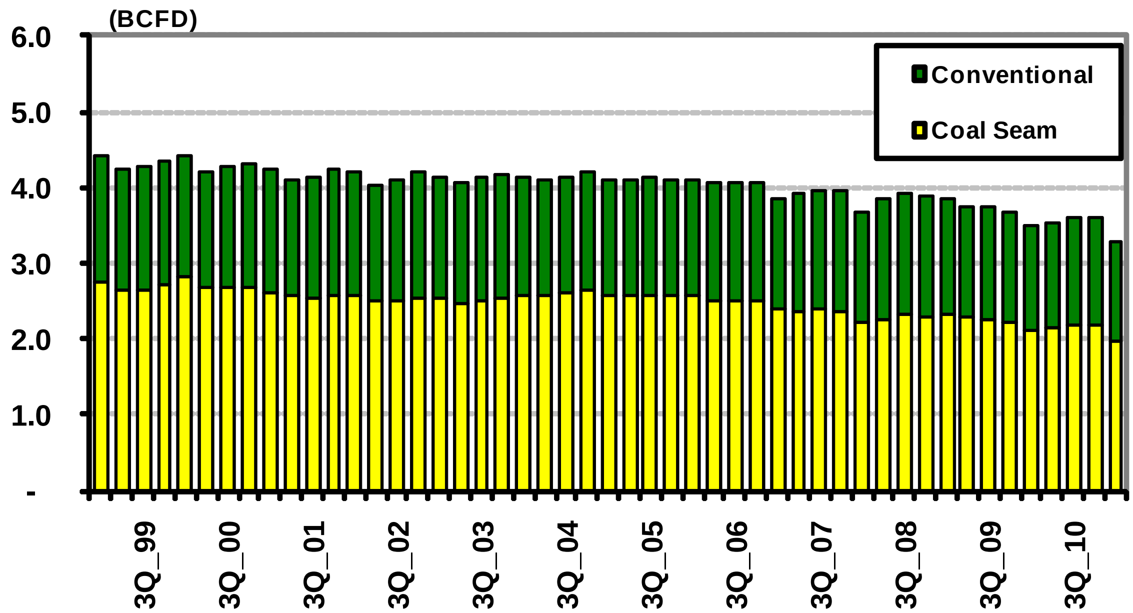


FIGURE C-6. SAN JUAN BASIN

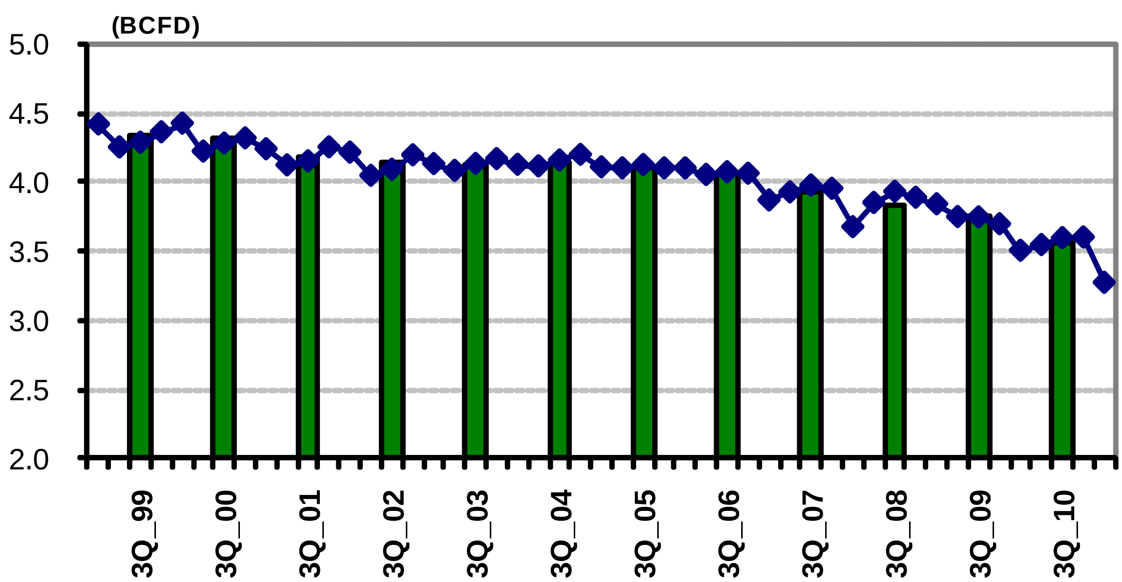


FIGURE C-7: ROCKY MOUNTAINS

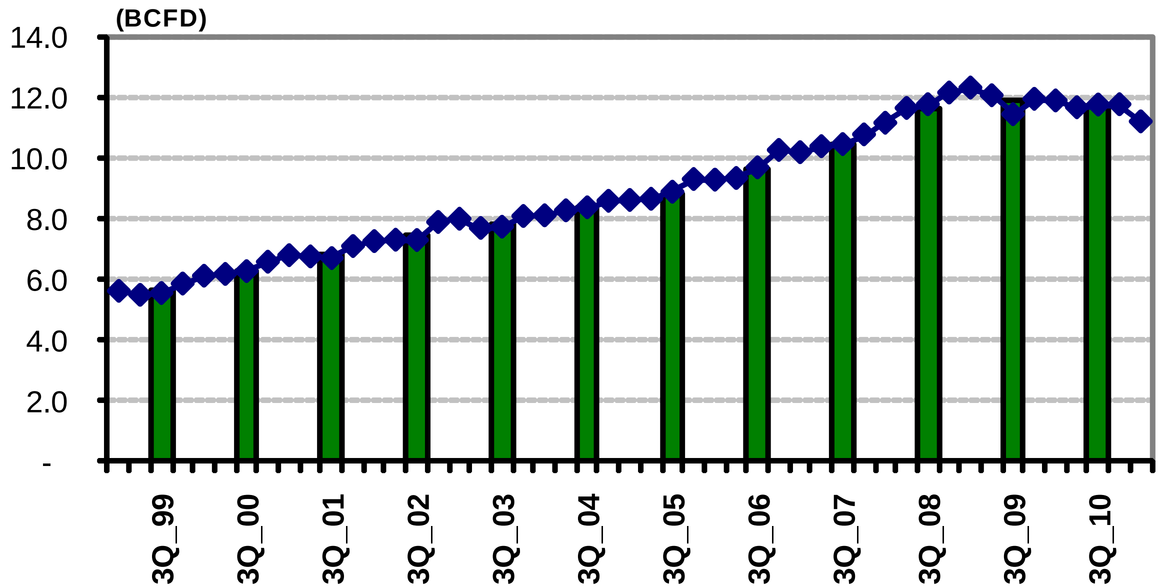


FIGURE C-8: WEST COAST

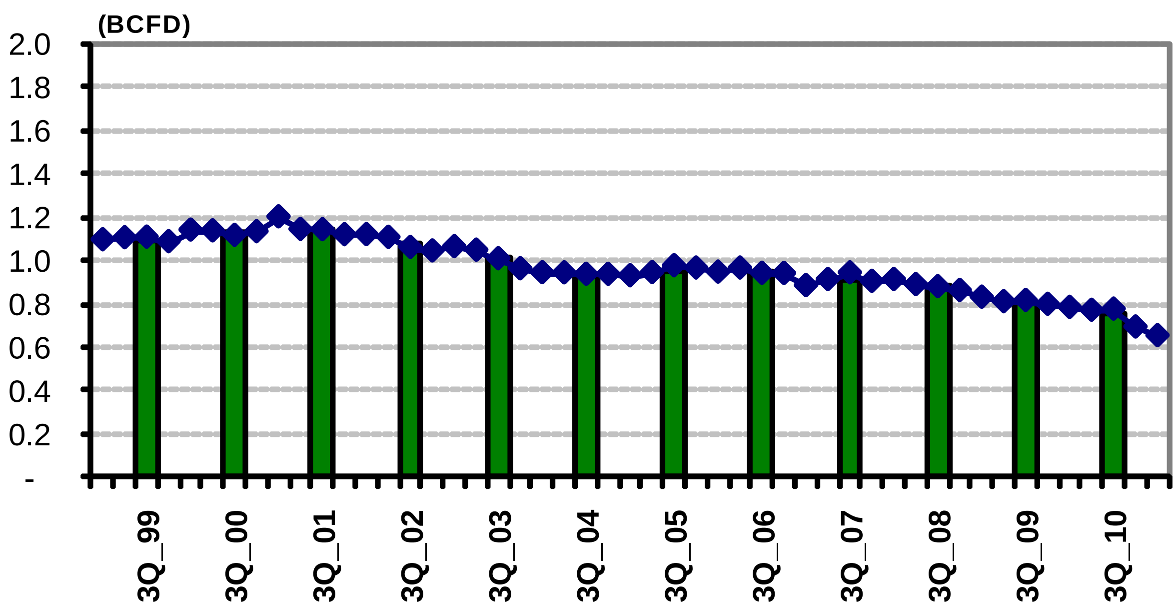


FIGURE C-9: EASTERN PRODUCTION BY CATEGORY

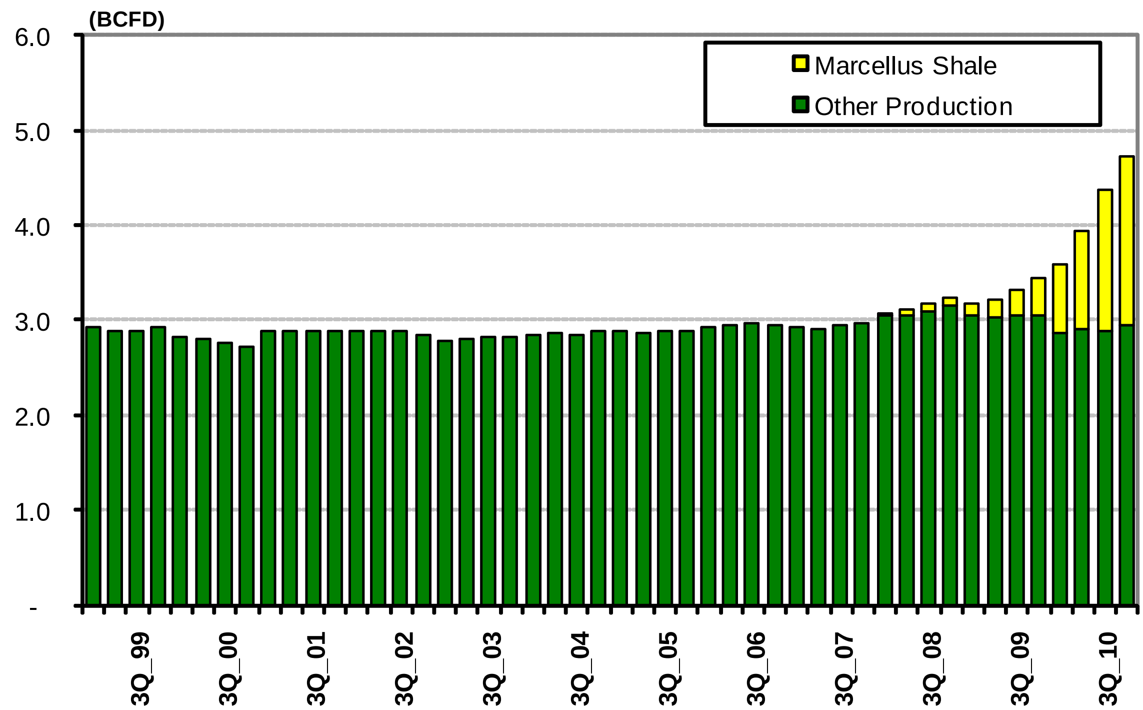


FIGURE C-10: TOTAL EASTERN PRODUCTION

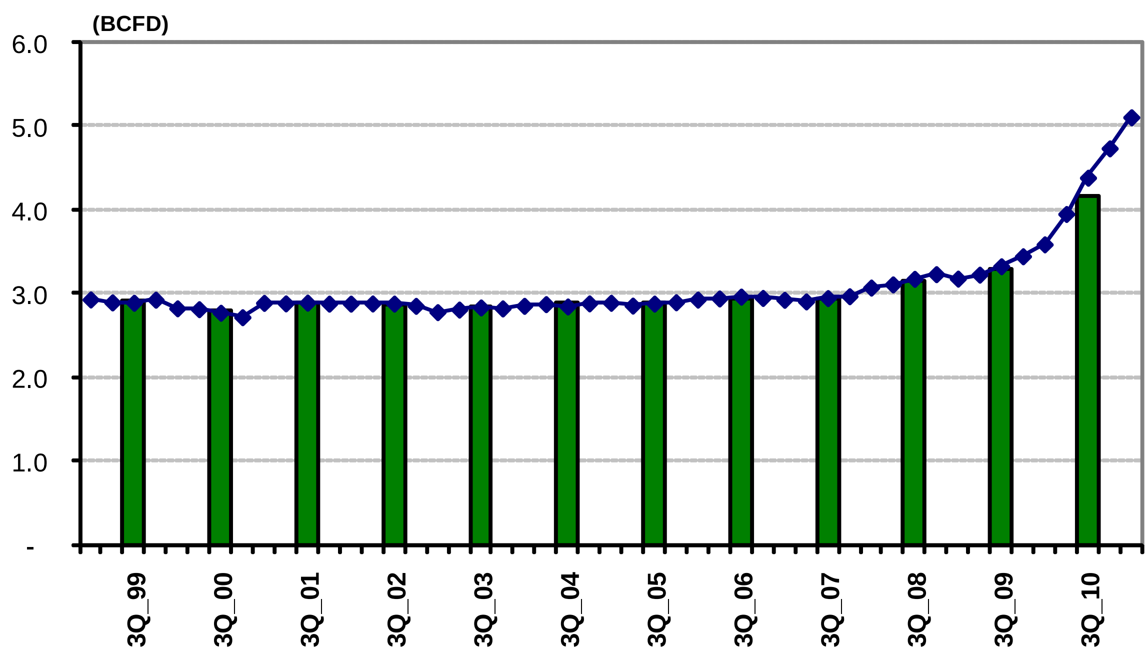


FIGURE C-11: NORTH AMERICAN REGASIFICATION CAPACITY

Terminal	Year End Capacity (MMCFD) (5)							Online Date	Comments (2) (6)
	2006	2007	2008	2009	2010	2011	2012		
Everett	915	915	915	915	915	915	915	1/88, 10/04	LT supply contract w/Trinidad.
Elba Island	806	806	806	806	1,211	1,211	1,706	12/01, 2/06, 3/10	Capacity 55% BG & 45% Shell.
Lake Charles	1,800	1,800	1,800	1,800	1,800	1,800	1,800	4/06, 7/06	Capacity 100% BG.
Cove Point	1,000	1,000	1,800	1,800	1,800	1,800	1,800	7/03, 12/04, 3/09, 12/12	Capacity 72% Statoil; 14% BP & 14% Shell.
Gulf Gateway	487	487	487	487	487	487	487	2/05(1)	100% spot supply.
N.W. Gateway	-	-	400	400	400	400	400	5/08(1)	100% spot supply.
Sabine Pass	-	-	4,000	4,000	4,000	4,000	4,000	5/08, 6/09	Capacity 38% Chevron; 38% Total & 24% Cheniere
Freeport LNG	-	-	2,650	2,650	2,650	2,650	2,650	6/08, 3/09	Capacity 67% Conoco: 33% Dow.
Cameron LNG	-	-	1,500	1,500	1,800	1,800	1,800	7/09	Capacity 33% SuezEnergy; 33% Sonatrach; 33% Sempra. (3)
Neptune LNG	-	-	-	-	400	400	400	3/10	
Golden Pass	-	-	-	-	-	2,000	2,000	3/11, 6/11	Capacity 70% Qatar; 20% Exxon; 10% Conoco
Gulf Clean Energy	-	-	-	-	-	1,300	1,300	1/2012	
Subtotal	5,008	5,008	9,508	14,358	15,463	17,463	19,258		
Tampico (Altamira)	500	500	500	500(4)	500	500	500	8/06	Capacity 50% Shell; 25% Total & 25% Mitsui.
Costa Azul	-	-	1,000	1,000(4)	1,000	1,000	1,000	5/08	Capacity 50% Shell & 50% Sempra.
Canaport	-	-	-	1,000(4)	1,000	1,000	1,000	6/09	Capacity and marketing 100% Repsol.
Subtotal	500	500	1,500	2,500	2,500	2,500	2,500		
Total	**5,508**	**5,508**	**11,008**	**16,858**	**17,963**	**19,963**	**21,758**		

FIGURE C-12. NORTH AMERICAN REGASIFICATION TERMINALS

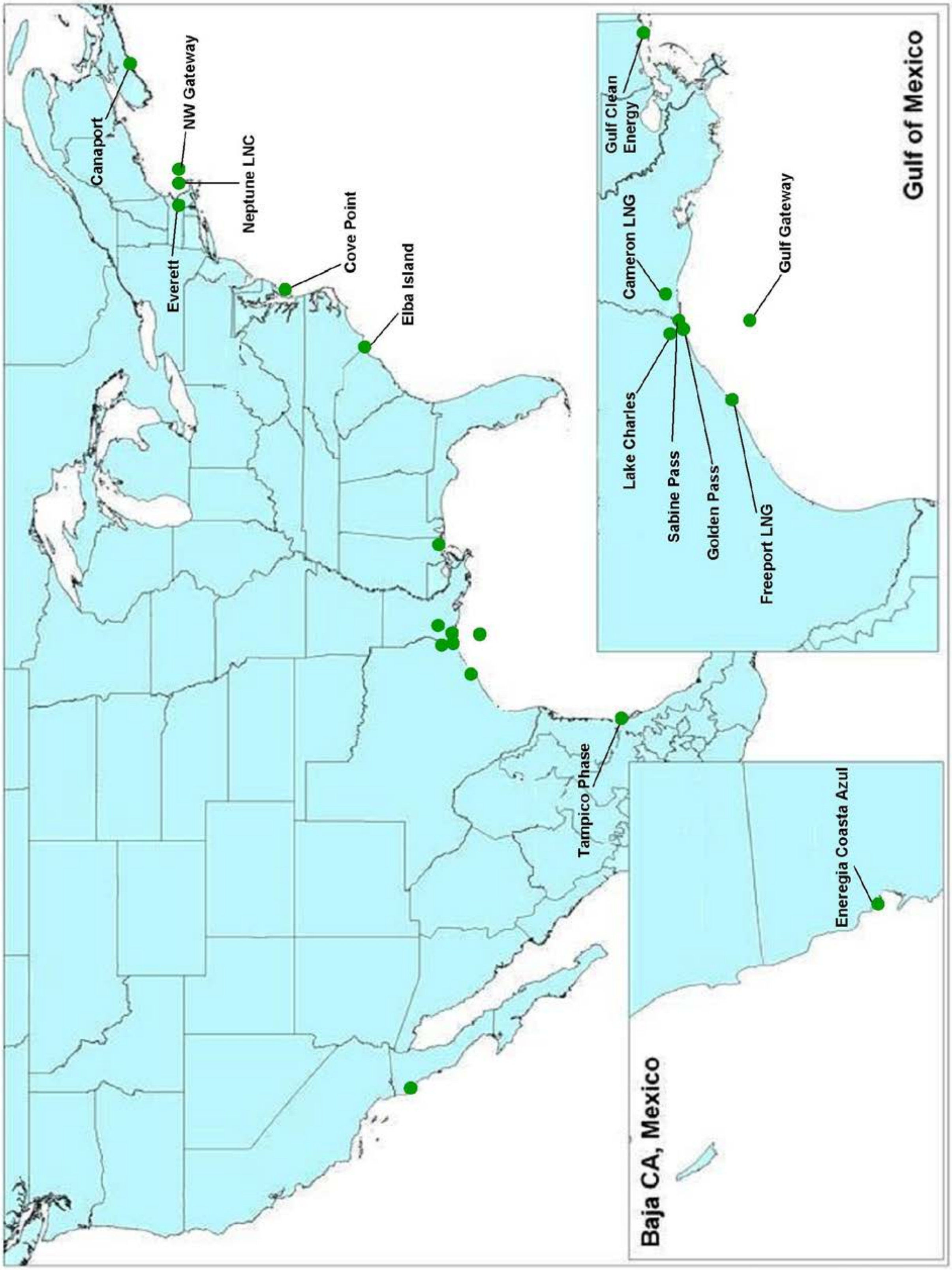
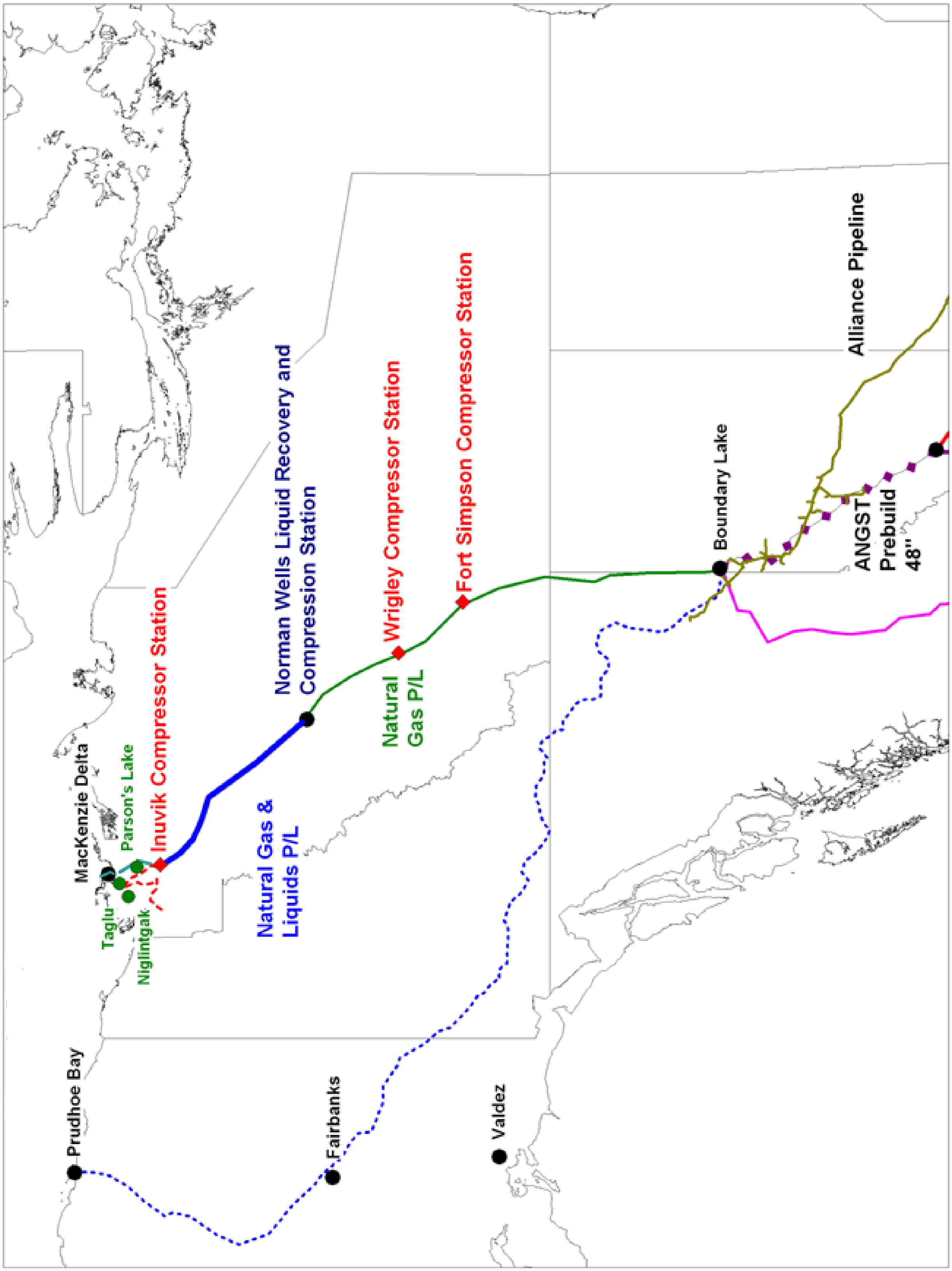
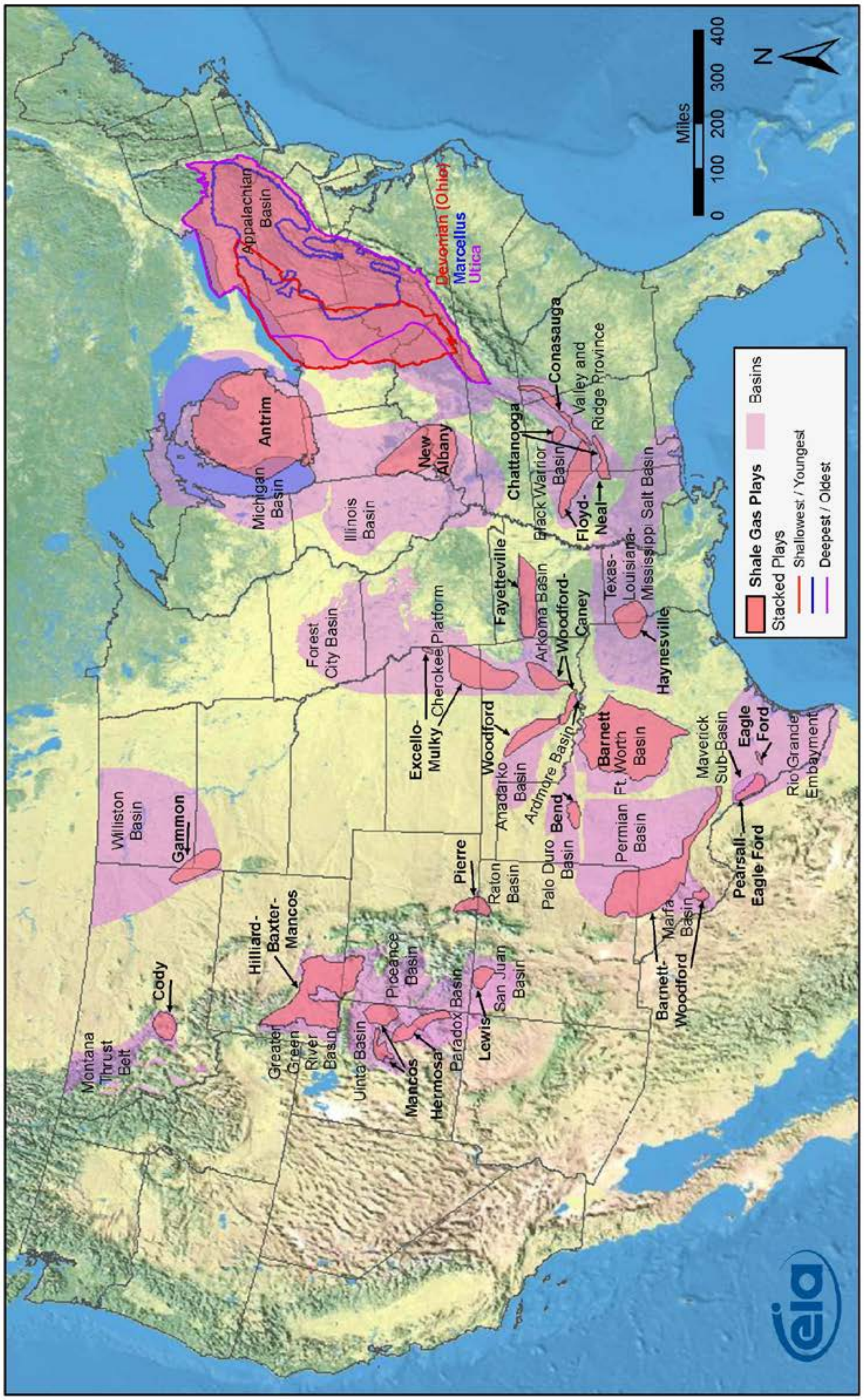


FIGURE C-13. ARCTIC GAS PIPELINES (WITHOUT SPUR TO VALDEZ, AR)



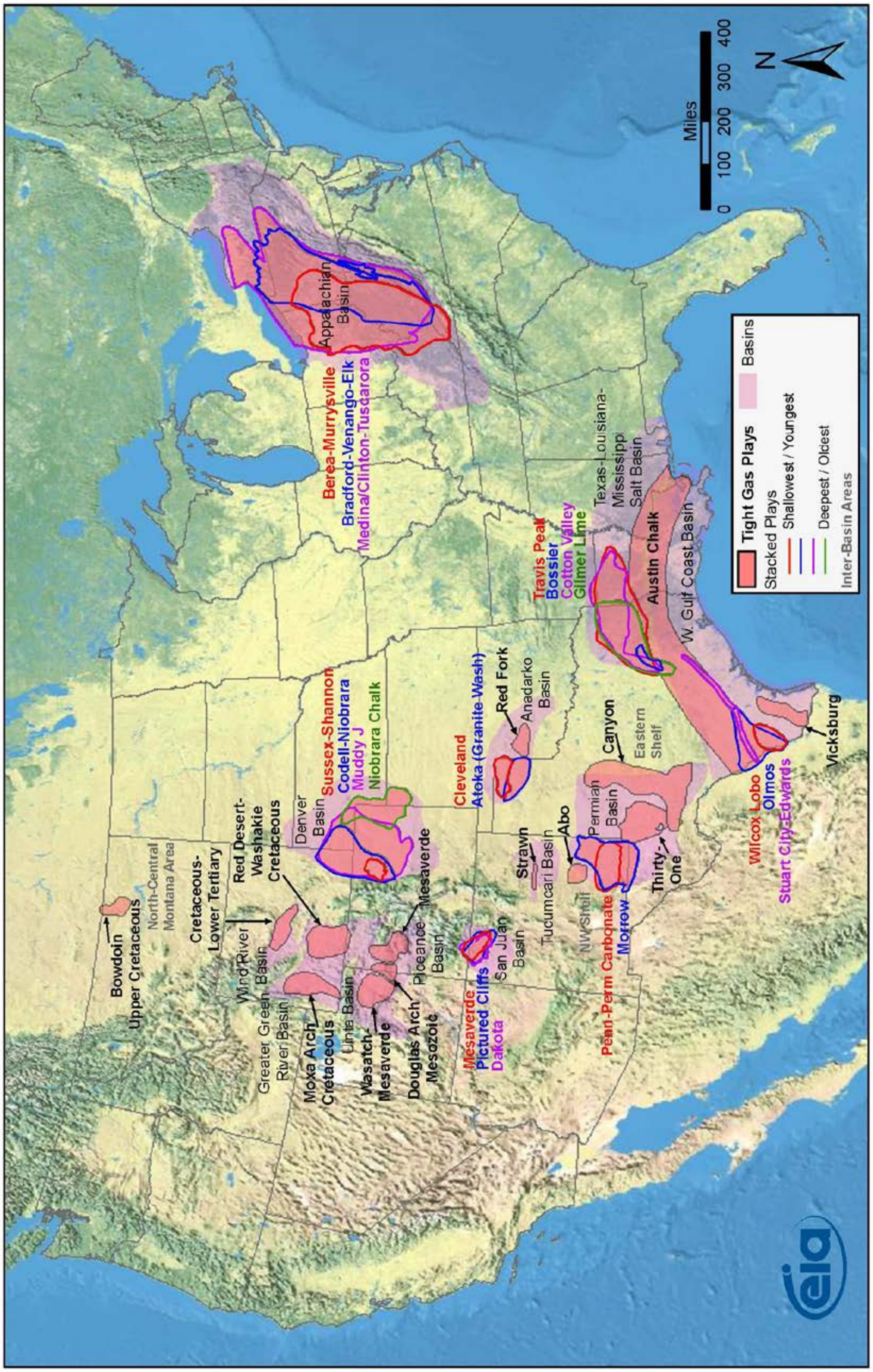
Appendix D: Maps

FIGURE D-1: SHALE GAS RESOURCE MAP



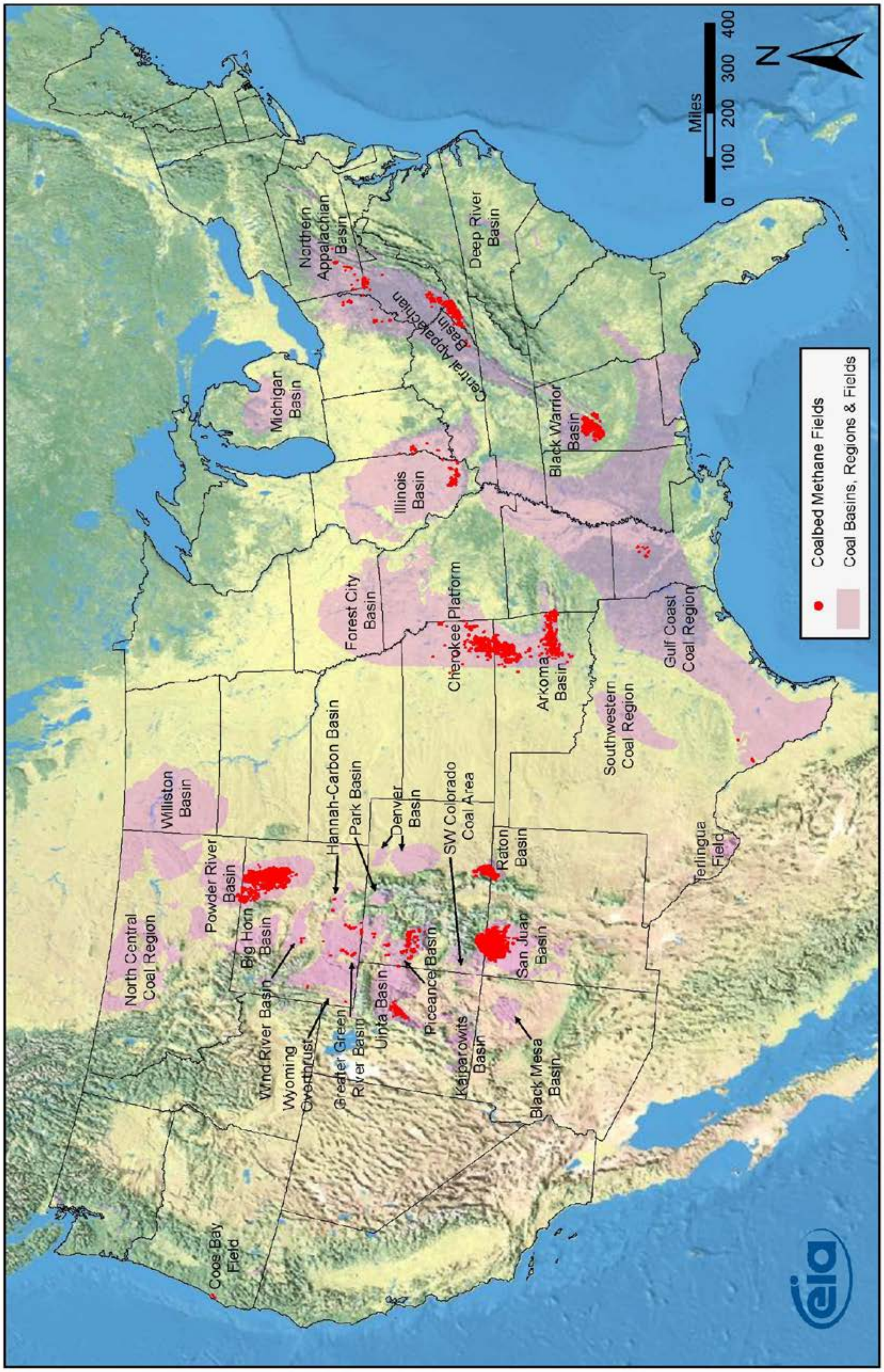
Source: Energy Information Administration based on data from various published studies
Updated: May 28, 2009

EXHIBIT D-2. TIGHT SANDS RESOURCE MAP



Source: Energy Information Administration based on data from various published studies
Updated: April 8, 2009

FIGURE D-3: COALBED METHANE RESOURCE MAP



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Appendix E: NERC Assessment Area Fuel Profiles

The figures shown in this appendix are developed using data collected for the 2011 Long-Term Reliability Assessment.[128] Existing and Projected resources include Existing-Certain, Existing-Other, Future-Planned and Future-Other supply categories. Conceptual resources are not included in these figures.

FIGURE E-1: PROJECTED NERC-WIDE NON-COINCIDENT SEASONAL ON-PEAK CAPACITY FUEL MIX

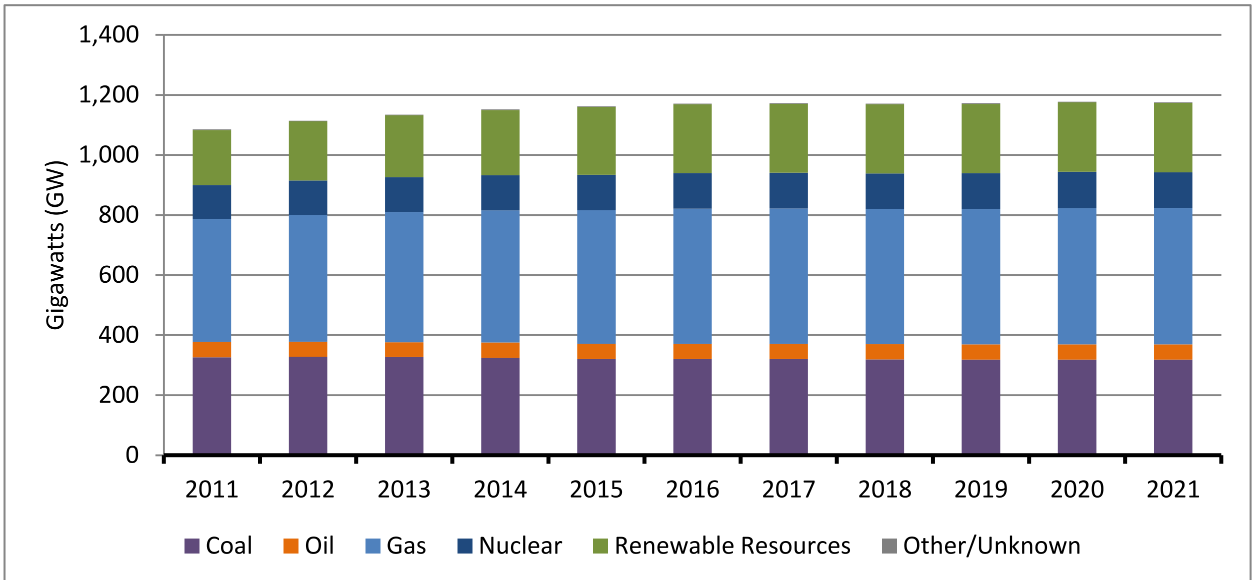
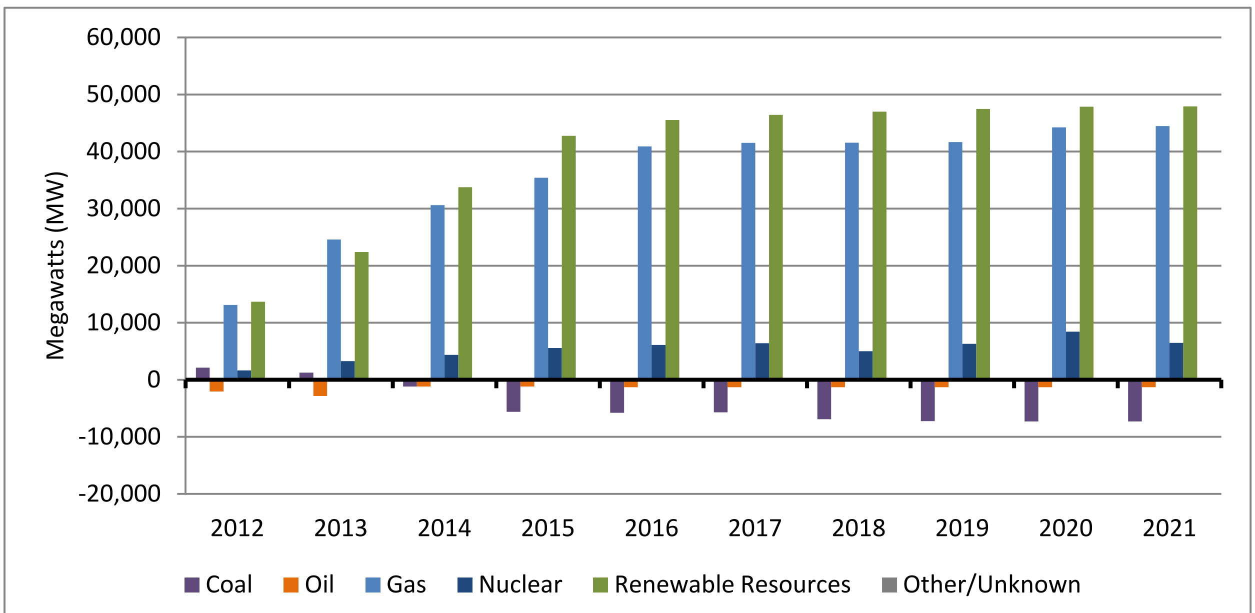


FIGURE E-2: PROJECTED CHANGE IN NERC-WIDE NON-COINCIDENT SEASONAL ON-PEAK CAPACITY FUEL MIX



[128] http://www.nerc.com/files/2011%20LTRA_Final.pdf

FIGURE E-3: PROJECTED ERCOT SUMMER ON-PEAK CAPACITY FUEL MIX

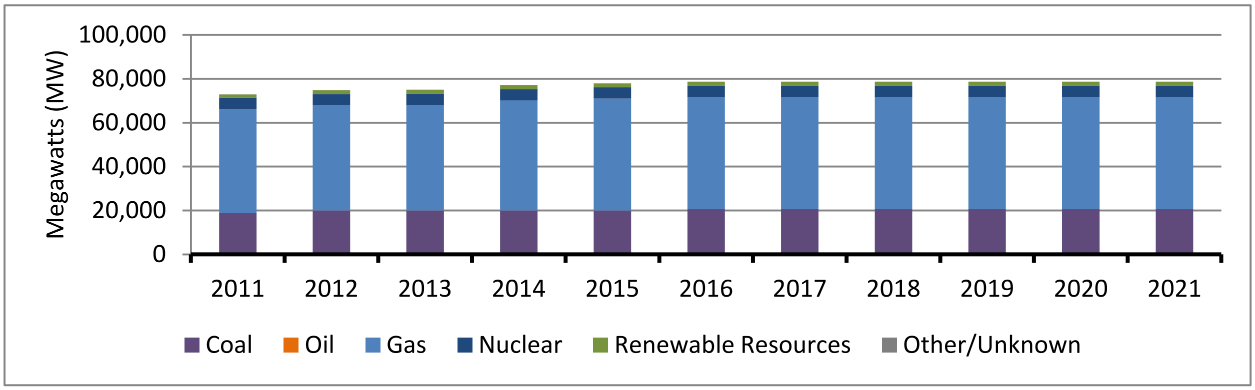


FIGURE E-4: PROJECTED CHANGE IN ERCOT SUMMER ON-PEAK CAPACITY FUEL MIX

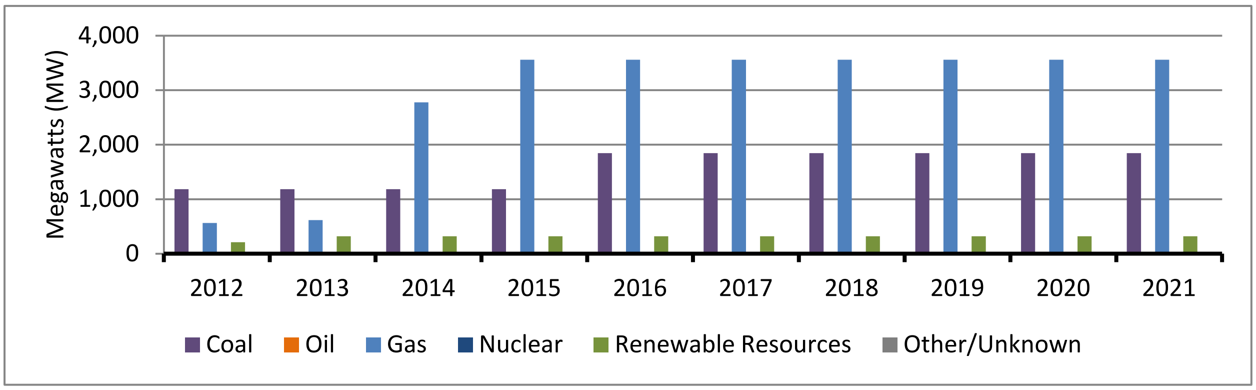


FIGURE E-5: PROJECTED FRCC SUMMER ON-PEAK CAPACITY FUEL MIX

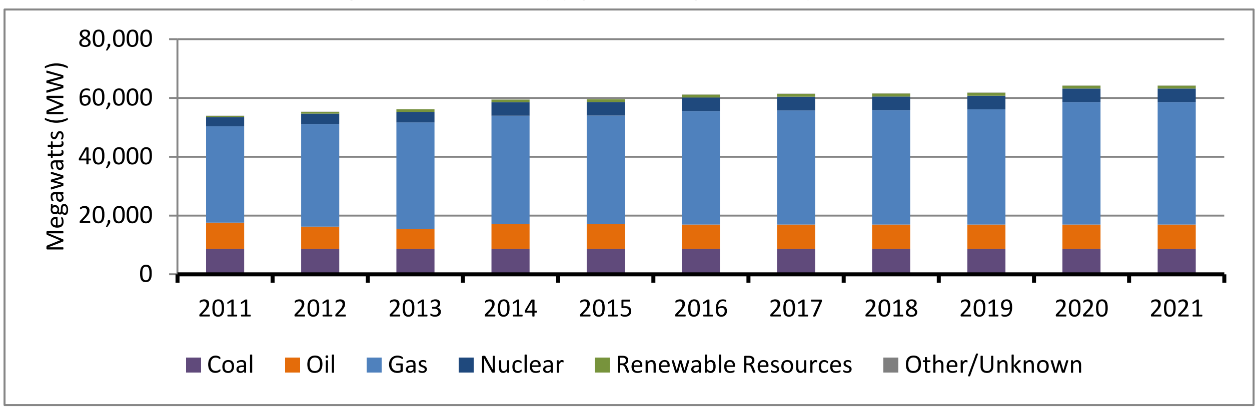


FIGURE E-6: PROJECTED CHANGE IN FRCC SUMMER ON-PEAK CAPACITY FUEL MIX

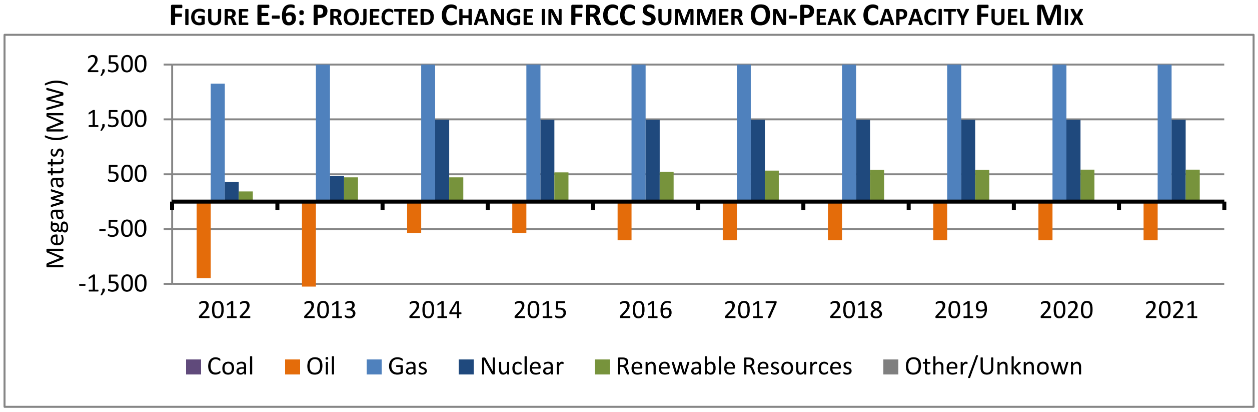


FIGURE E-7: PROJECTED MISO SUMMER ON-PEAK CAPACITY FUEL MIX

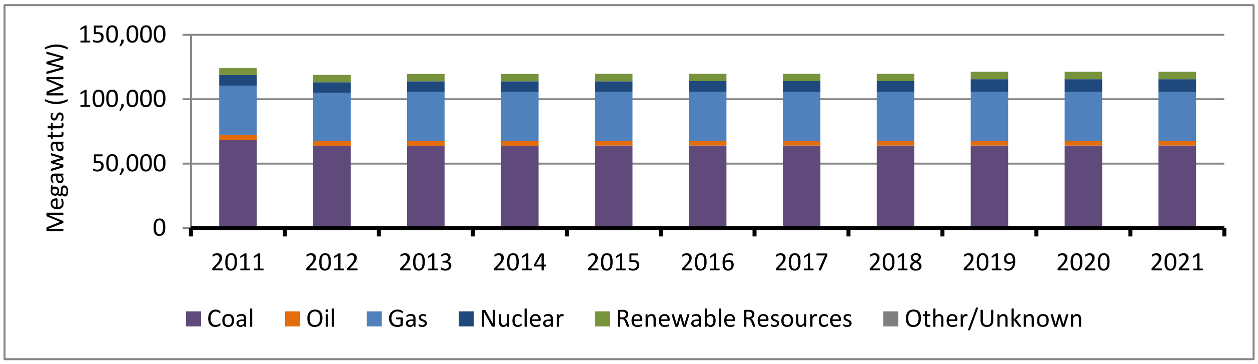


FIGURE E-8: PROJECTED CHANGE IN MISO SUMMER ON-PEAK CAPACITY FUEL MIX[129]

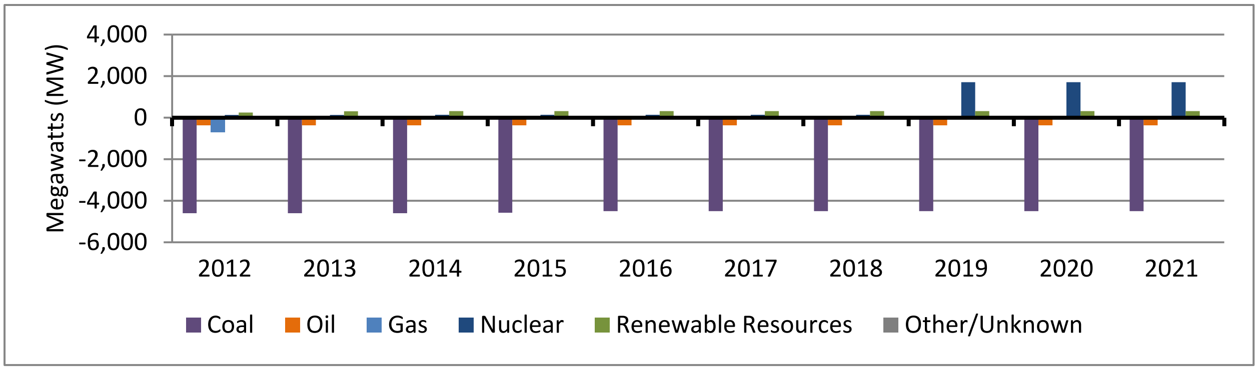


FIGURE E-9: PROJECTED MRO-MANITOBA WINTER ON-PEAK CAPACITY FUEL MIX

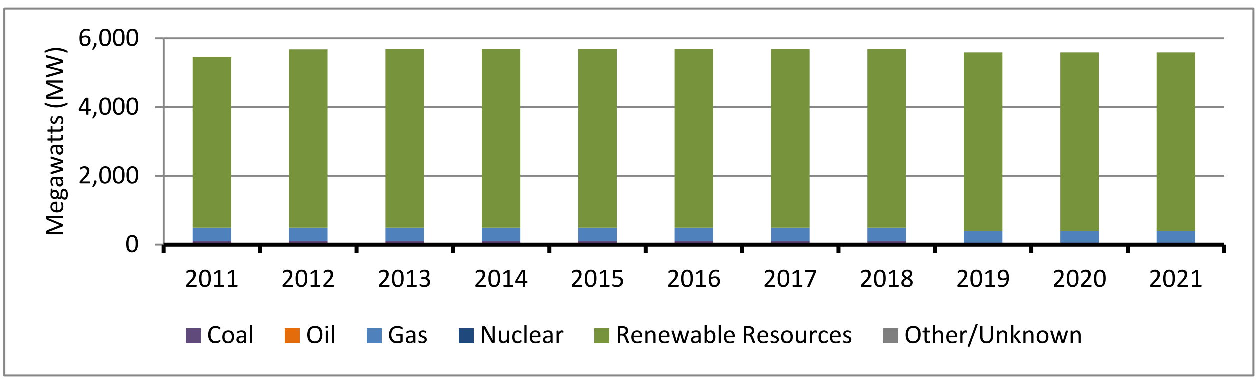
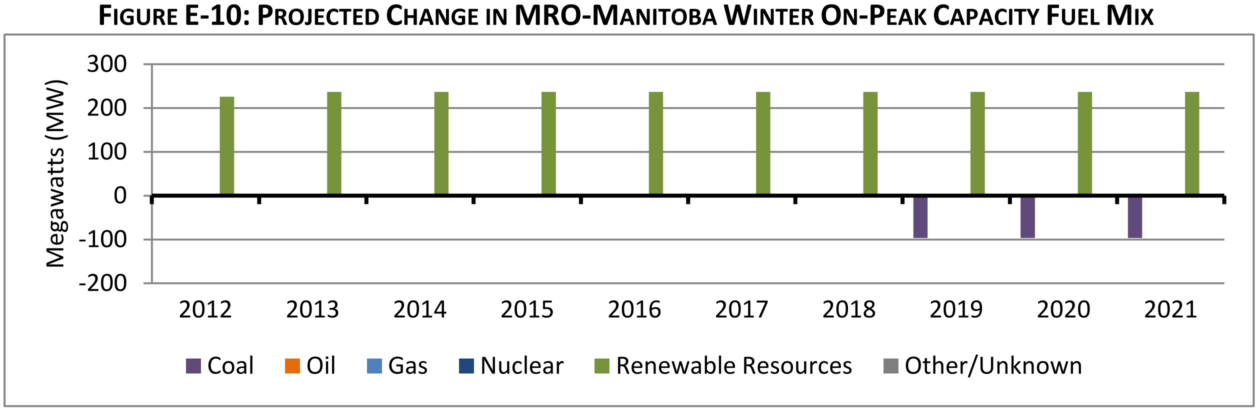


FIGURE E-10: PROJECTED CHANGE IN MRO-MANITOBA WINTER ON-PEAK CAPACITY FUEL MIX



[129] Change in coal capacity is mostly due to entities switching from MISO to PJM.

Figure E-11: Projected MRO-MAPP Summer On-Peak Capacity Fuel Mix

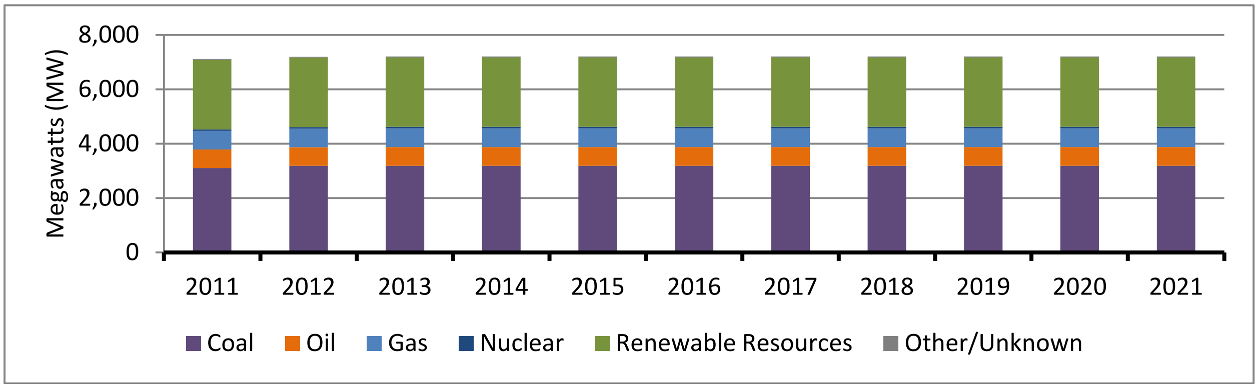


Figure E-12: Projected Change in MRO-MAPP Summer On-Peak Capacity Fuel Mix

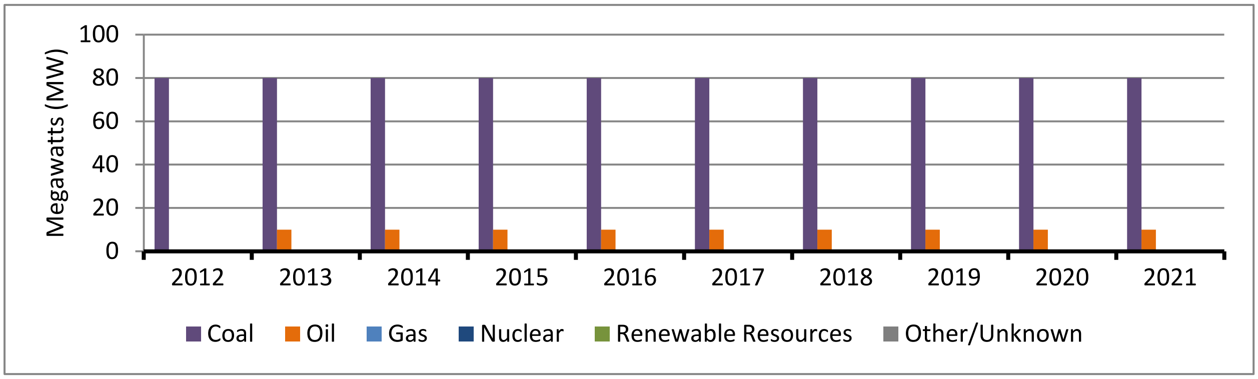


Figure E-13: Projected MRO-SaskPower Winter On-Peak Capacity Fuel Mix

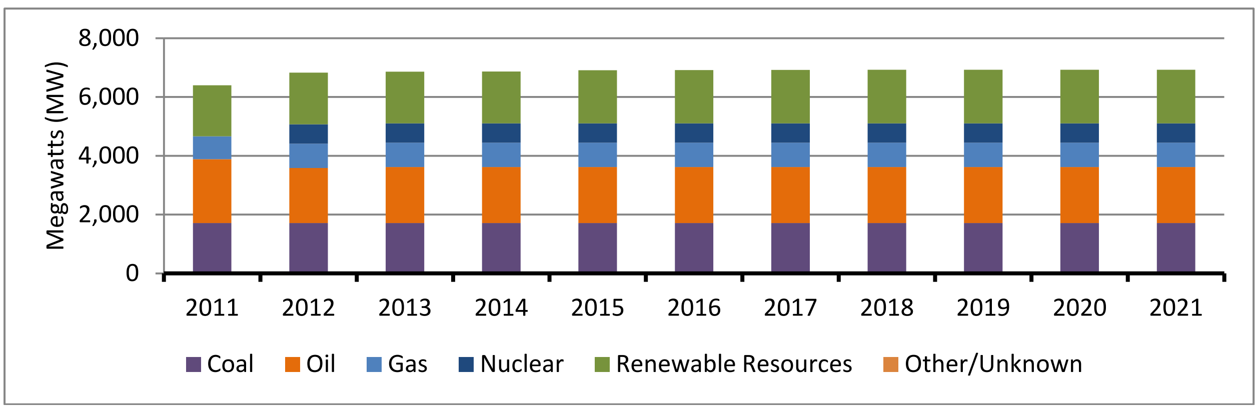


Figure E-14: Projected Change in MRO-SaskPower Winter On-Peak Capacity Fuel Mix

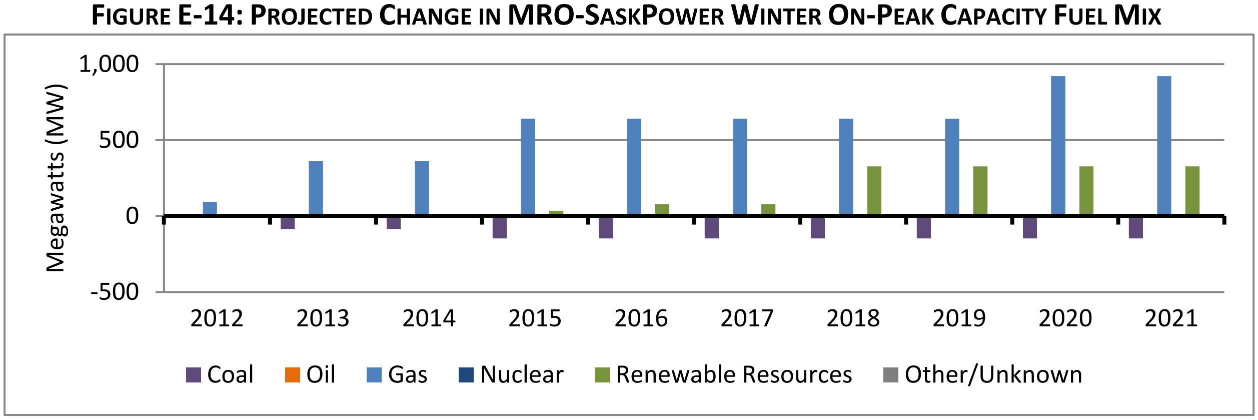


FIGURE E-15: PROJECTED NPCC-MARITIMES WINTER ON-PEAK CAPACITY FUEL MIX

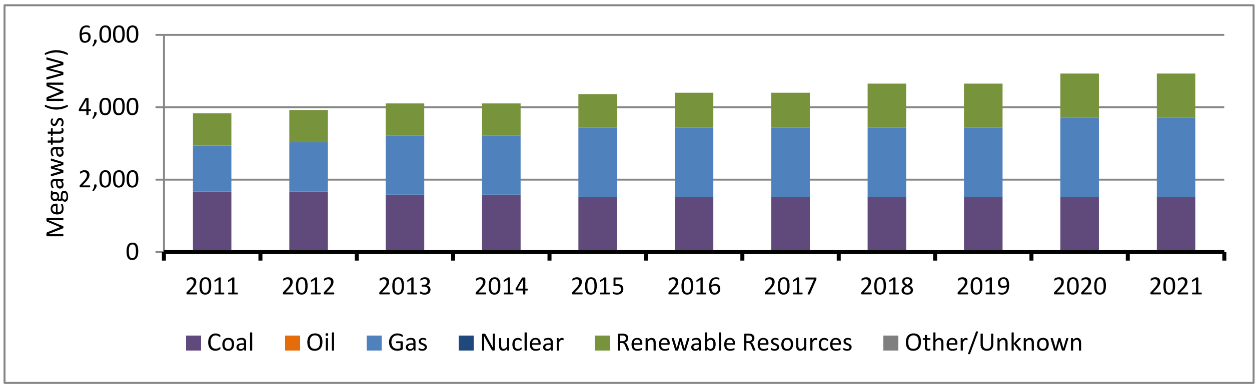


FIGURE E-16: PROJECTED CHANGE IN NPCC-MARITIMES WINTER ON-PEAK CAPACITY FUEL MIX

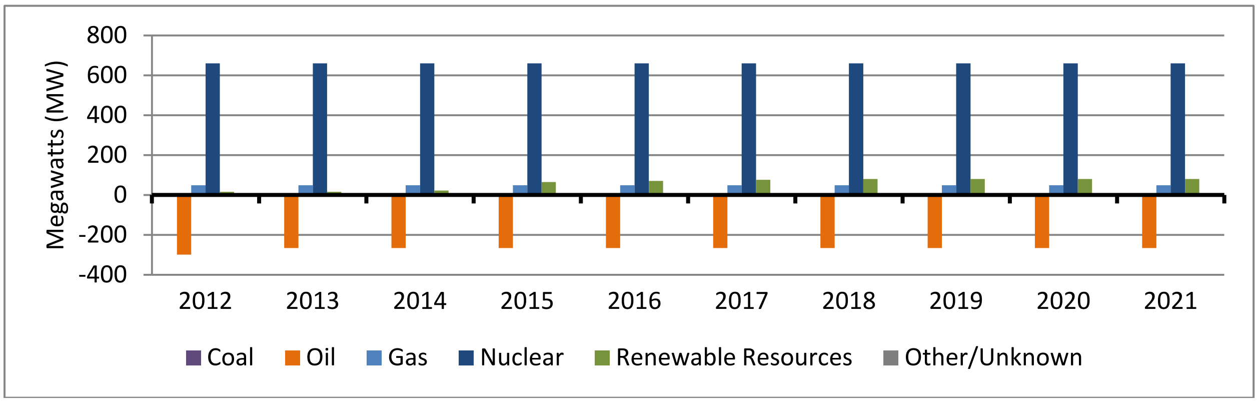


FIGURE E-17: PROJECTED NPCC-NEW ENGLAND SUMMER ON-PEAK CAPACITY FUEL MIX

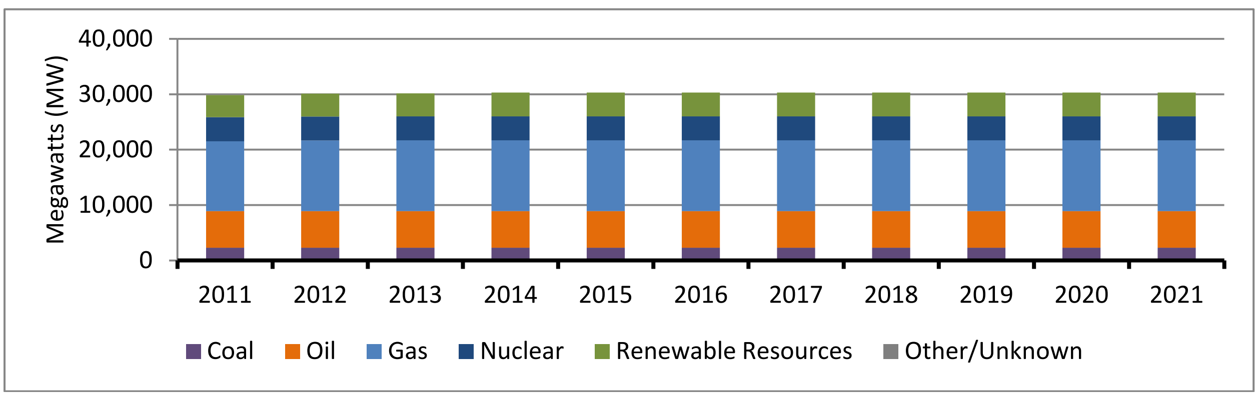


FIGURE E-18: PROJECTED CHANGE IN NPCC-NEW ENGLAND SUMMER ON-PEAK CAPACITY FUEL MIX

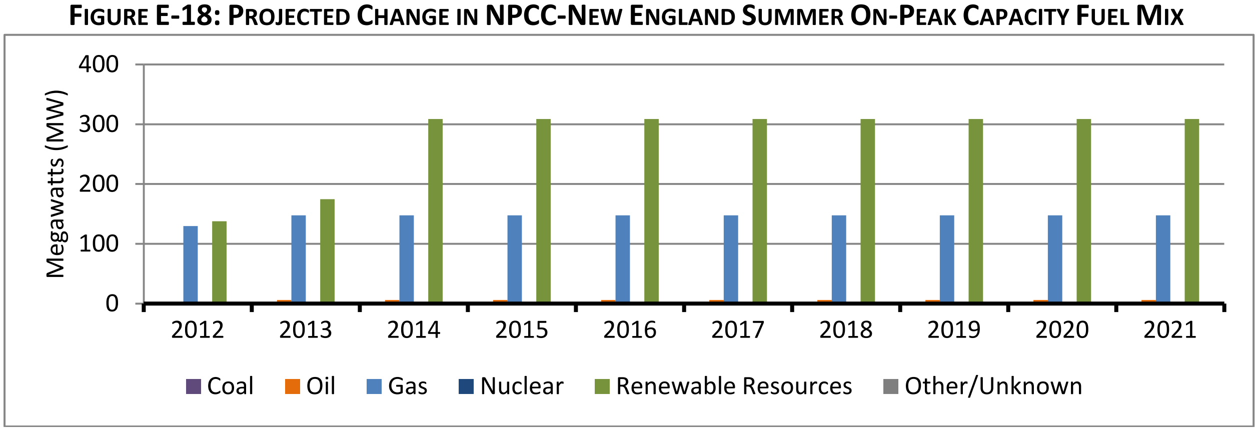


FIGURE E-19: PROJECTED NPCC-NEW YORK SUMMER ON-PEAK CAPACITY FUEL MIX

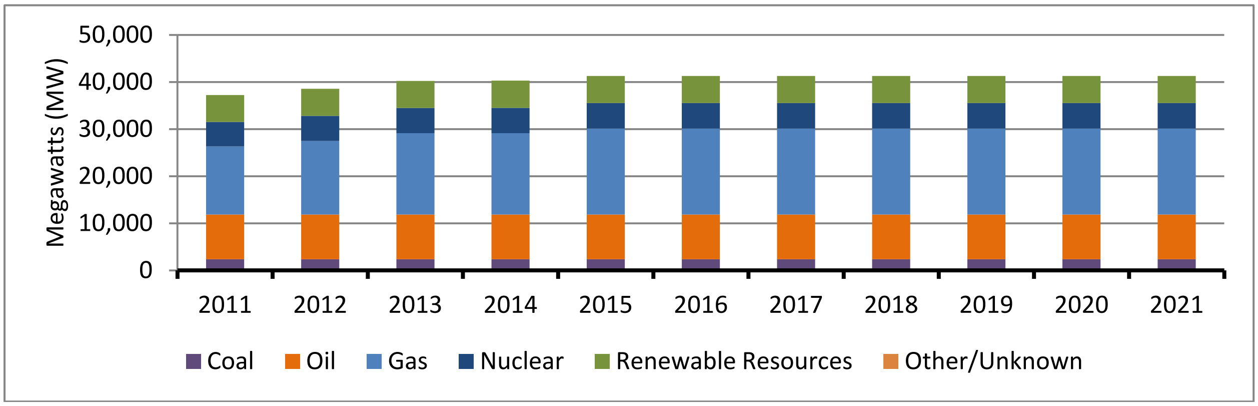


FIGURE E-20: PROJECTED CHANGE IN NPCC-NEW YORK SUMMER ON-PEAK CAPACITY FUEL MIX

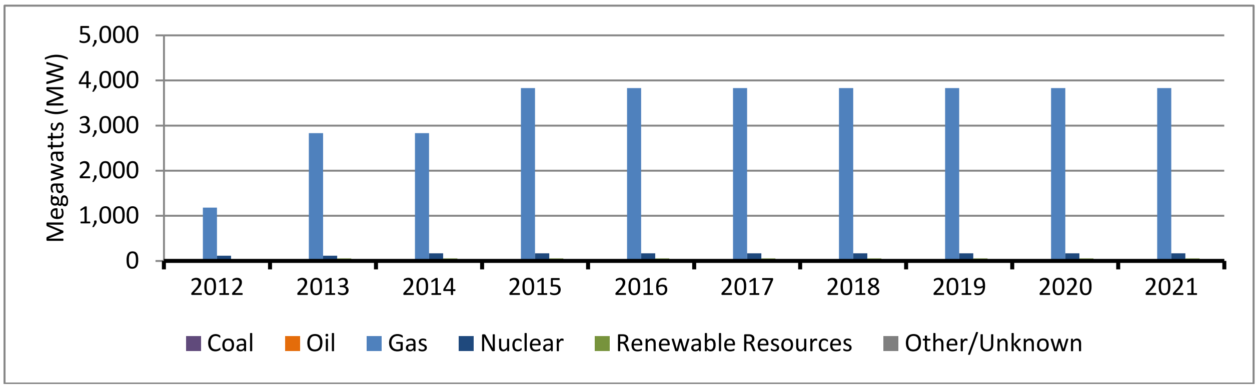


FIGURE E-21: PROJECTED NPCC-ONTARIO SUMMER ON-PEAK CAPACITY FUEL MIX

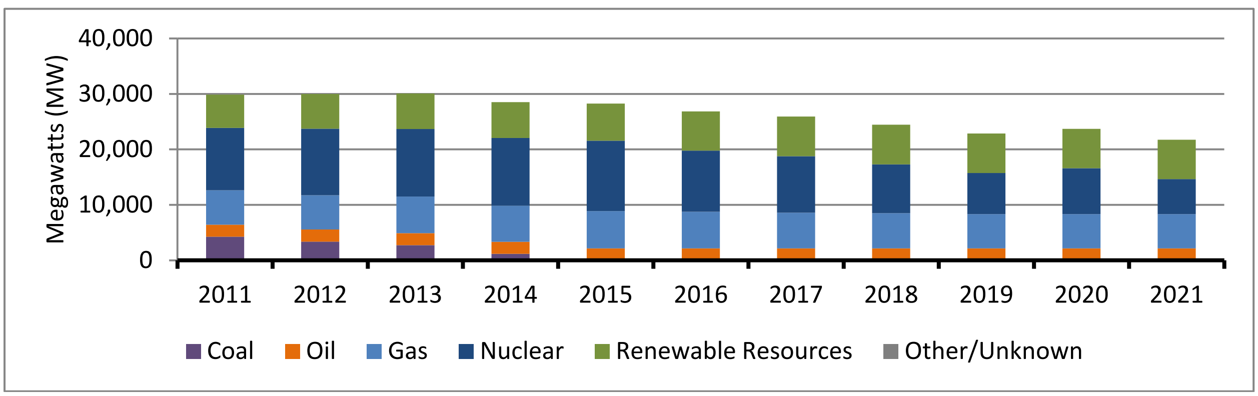


FIGURE E-22: PROJECTED CHANGE IN NPCC-ONTARIO SUMMER ON-PEAK CAPACITY FUEL MIX

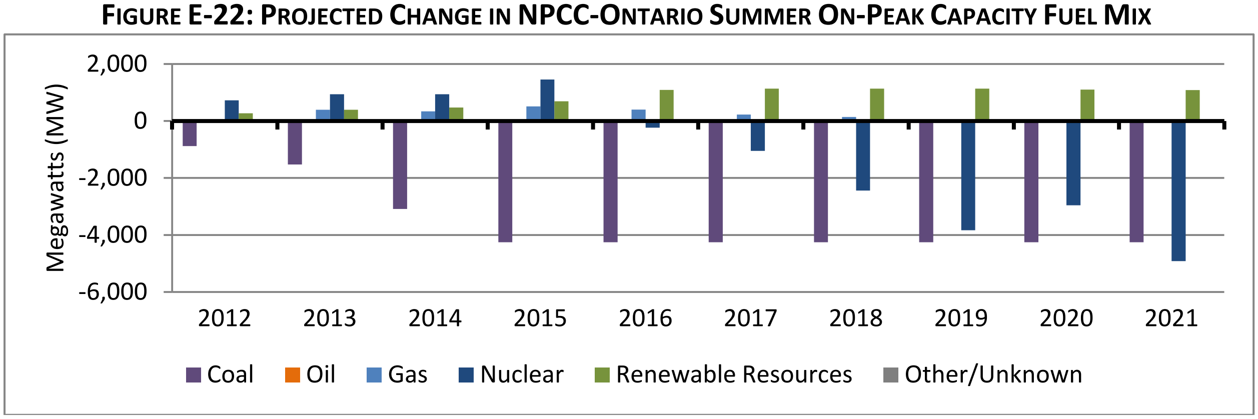


FIGURE E-23: PROJECTED NPCC- QUÉBEC WINTER ON-PEAK CAPACITY FUEL MIX

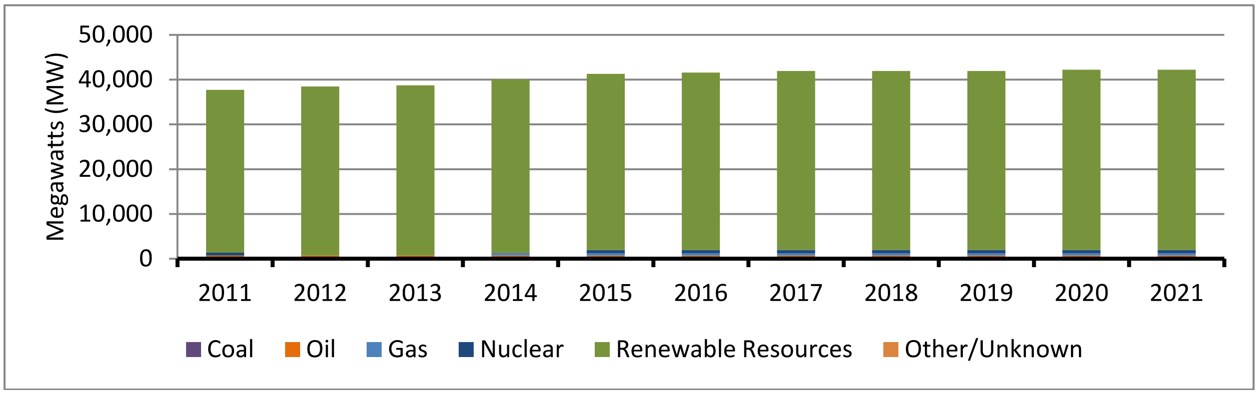


FIGURE E-24: PROJECTED CHANGE IN NPCC- QUÉBEC WINTER ON-PEAK CAPACITY FUEL MIX

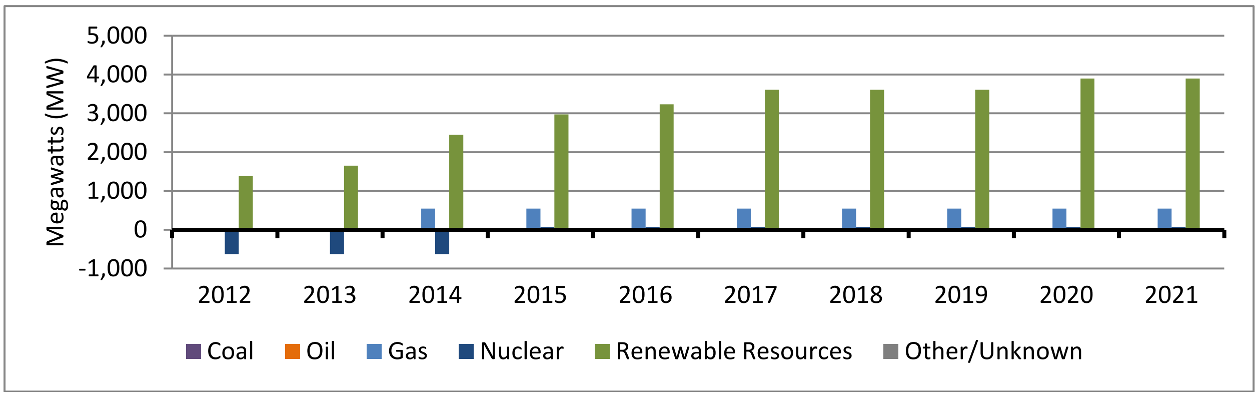


FIGURE E-25: PROJECTED PJM SUMMER ON-PEAK CAPACITY FUEL MIX

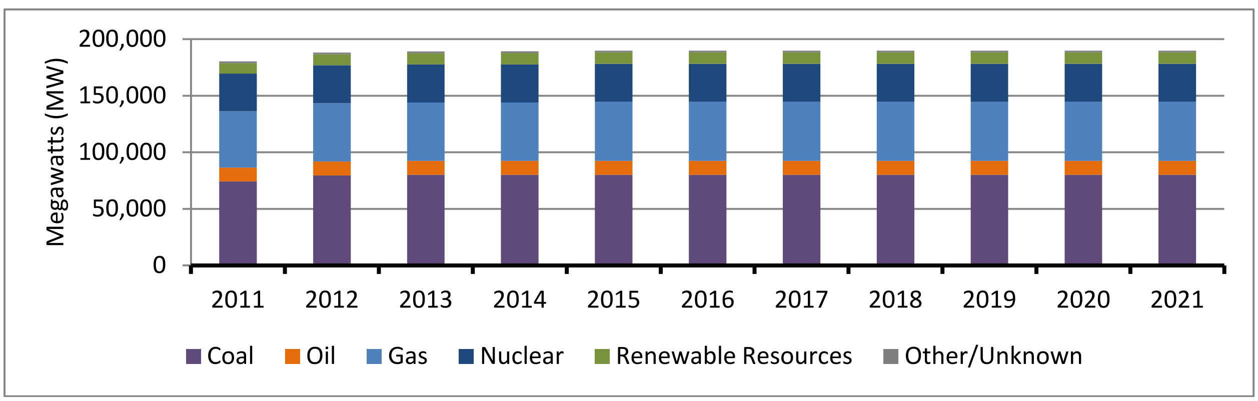


FIGURE E-26: PROJECTED CHANGE IN PJM SUMMER ON-PEAK CAPACITY FUEL MIX

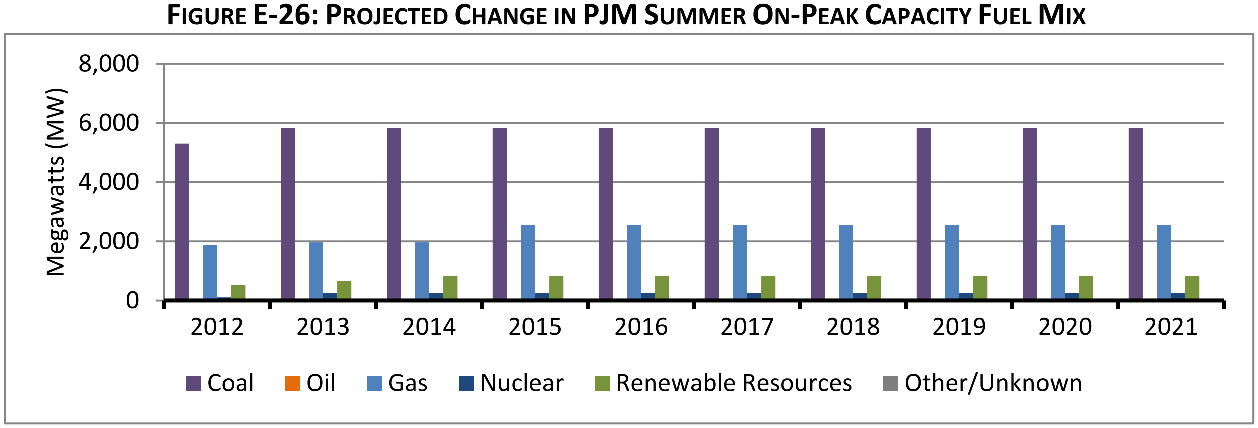


FIGURE E-27: PROJECTED SERC-E SUMMER ON-PEAK CAPACITY FUEL MIX

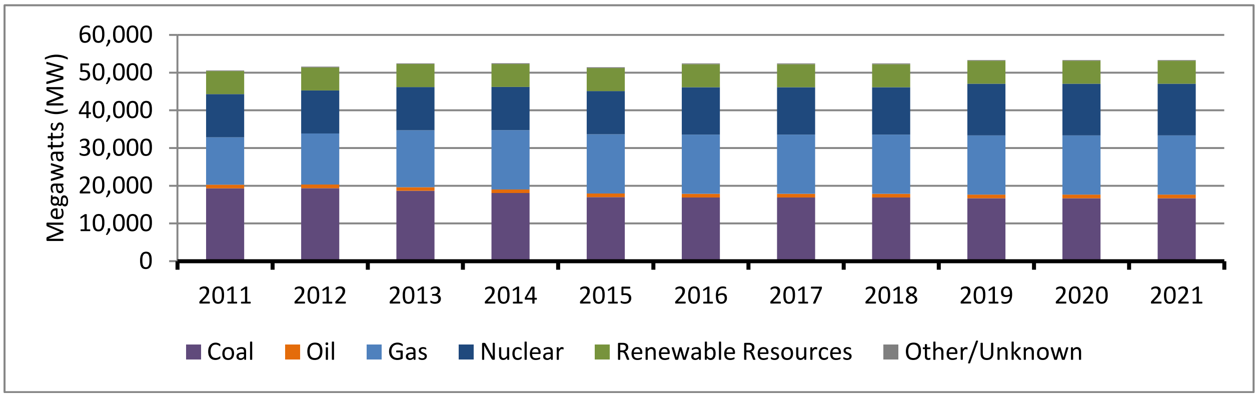


FIGURE E-28: PROJECTED SERC-E SUMMER ON-PEAK CAPACITY FUEL MIX

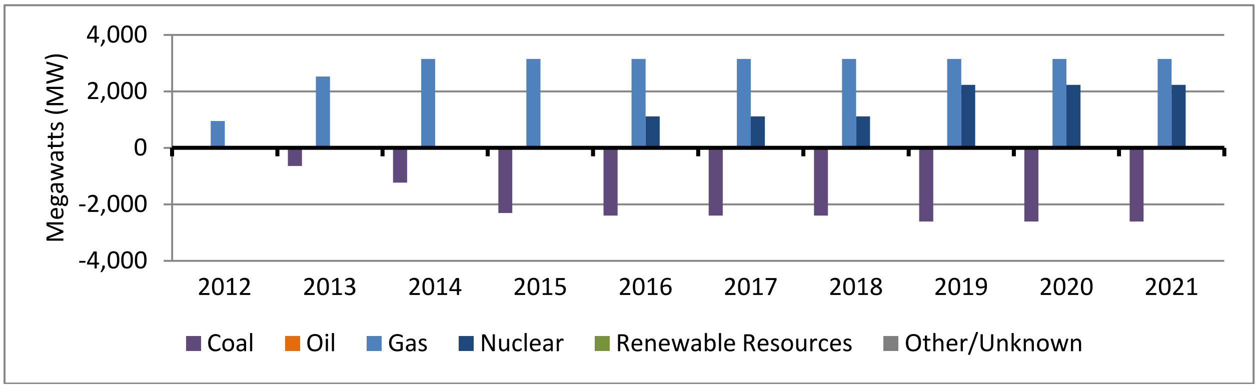


FIGURE E-29: PROJECTED CHANGE IN SERC-N SUMMER ON-PEAK CAPACITY FUEL MIX

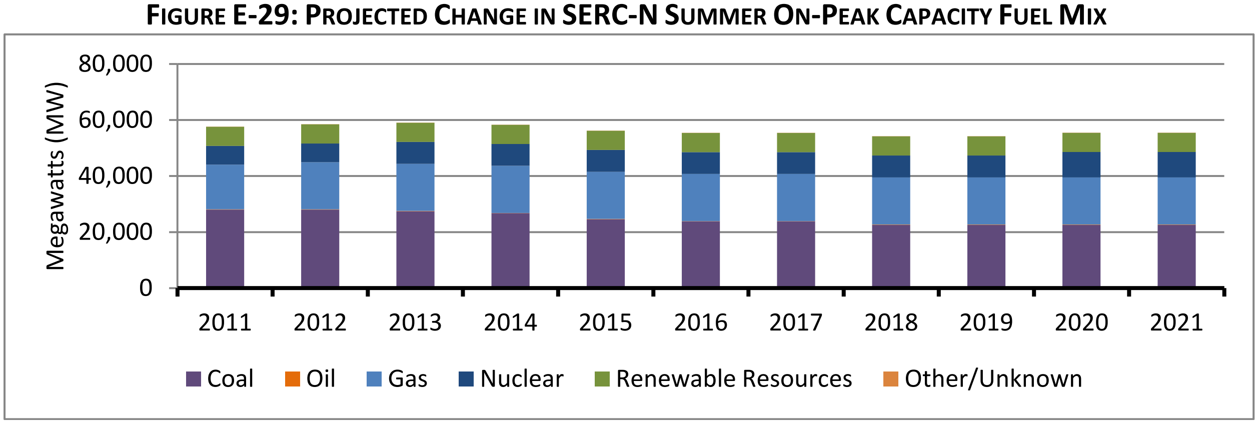


FIGURE E-30: PROJECTED CHANGE IN SERC-N SUMMER ON-PEAK CAPACITY FUEL MIX

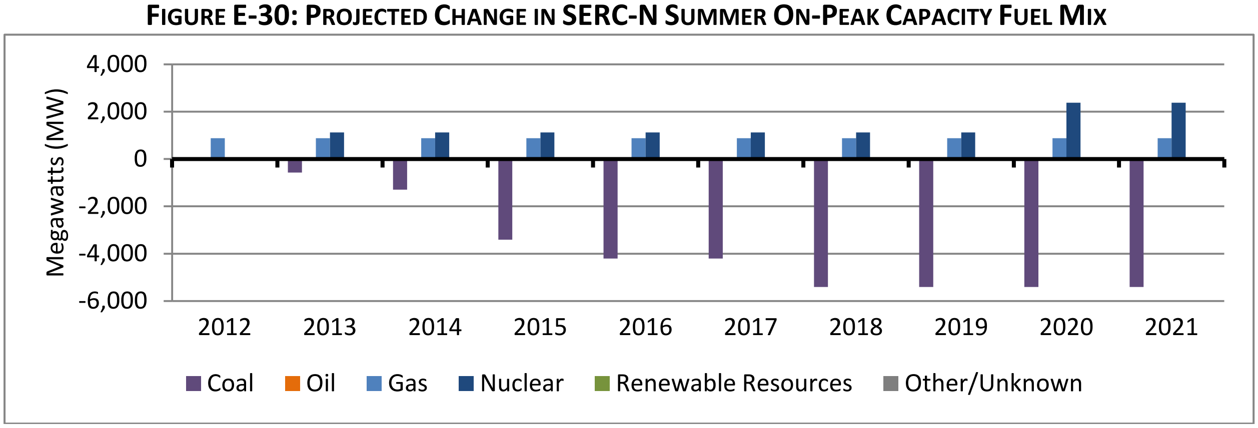


FIGURE E-31: PROJECTED SERC-SE SUMMER ON-PEAK CAPACITY FUEL MIX

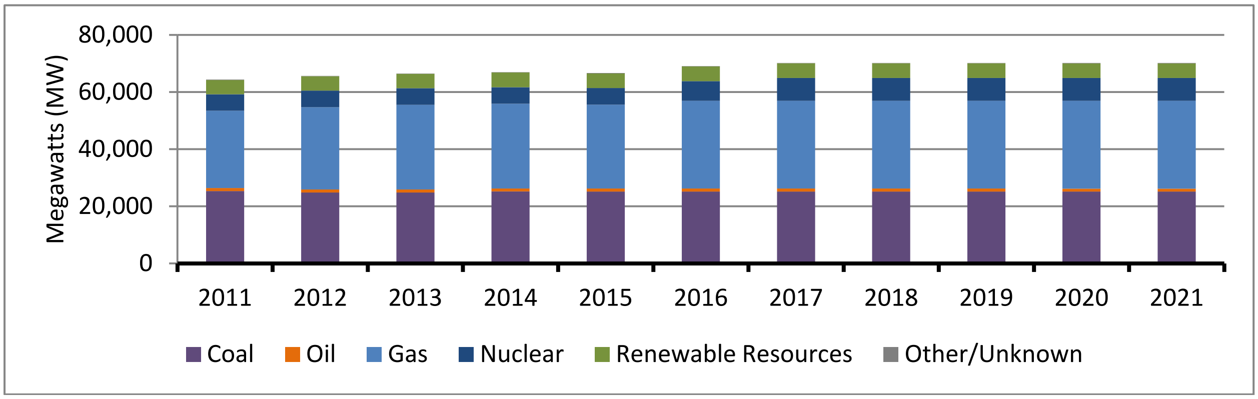


FIGURE E-32: PROJECTED CHANGE IN SERC-SE SUMMER ON-PEAK CAPACITY FUEL MIX

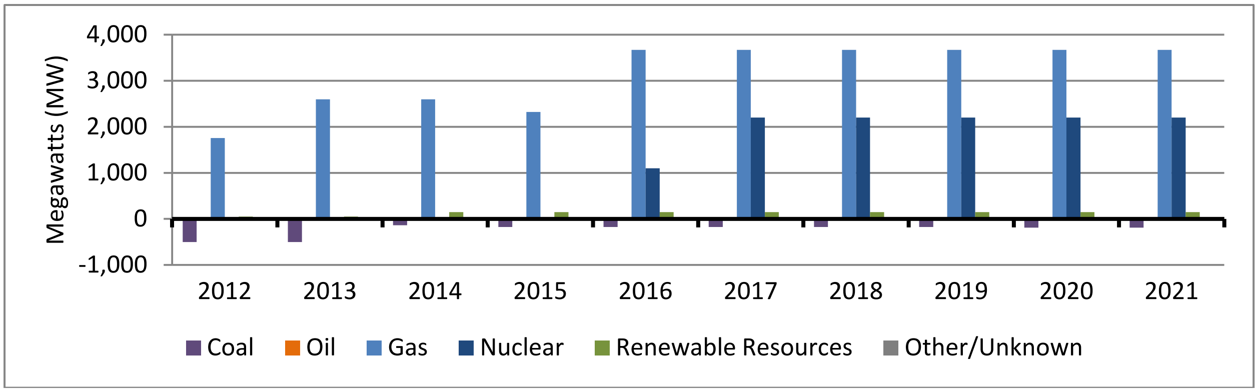


FIGURE E-33: PROJECTED SERC-E SUMMER ON-PEAK CAPACITY FUEL MIX

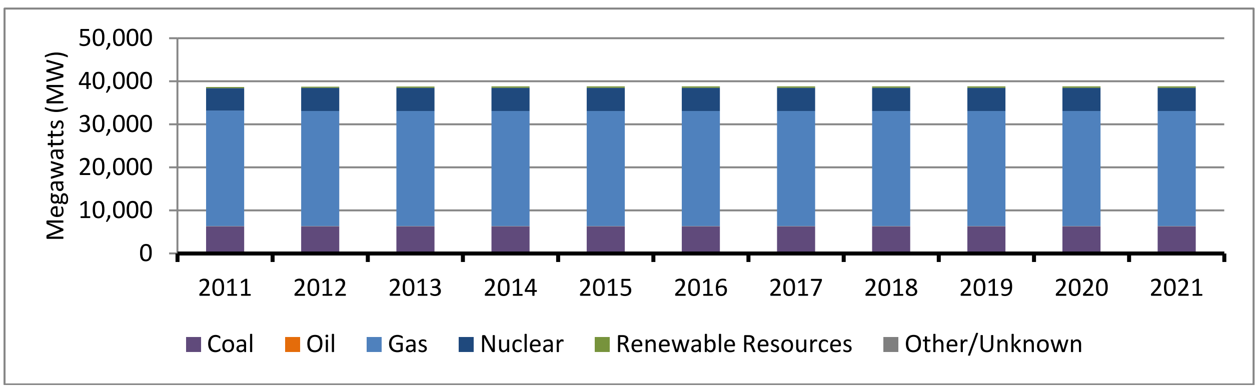


FIGURE E-34: PROJECTED CHANGE IN SERC-E SUMMER ON-PEAK CAPACITY FUEL MIX

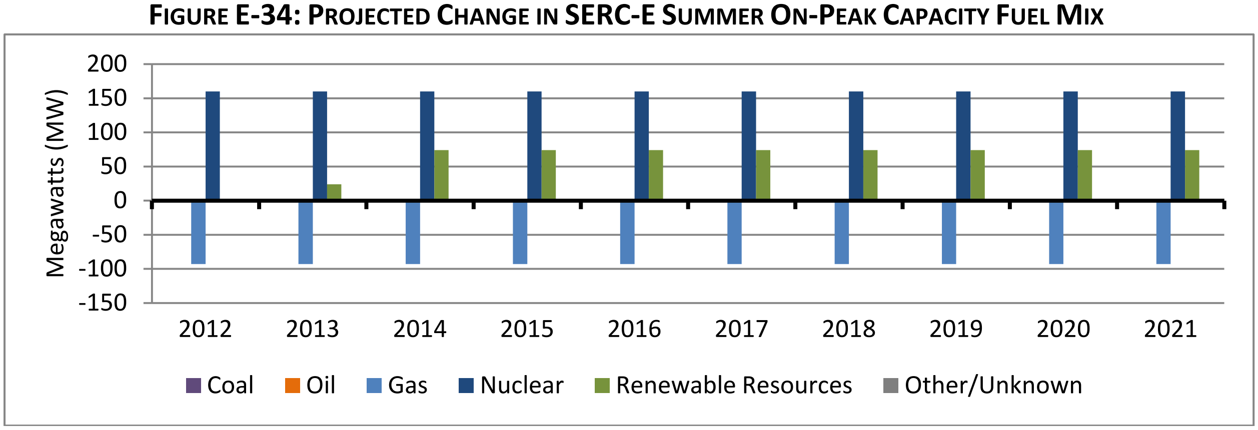


Figure E-35: Projected SERC-W Summer On-Peak Capacity Fuel Mix

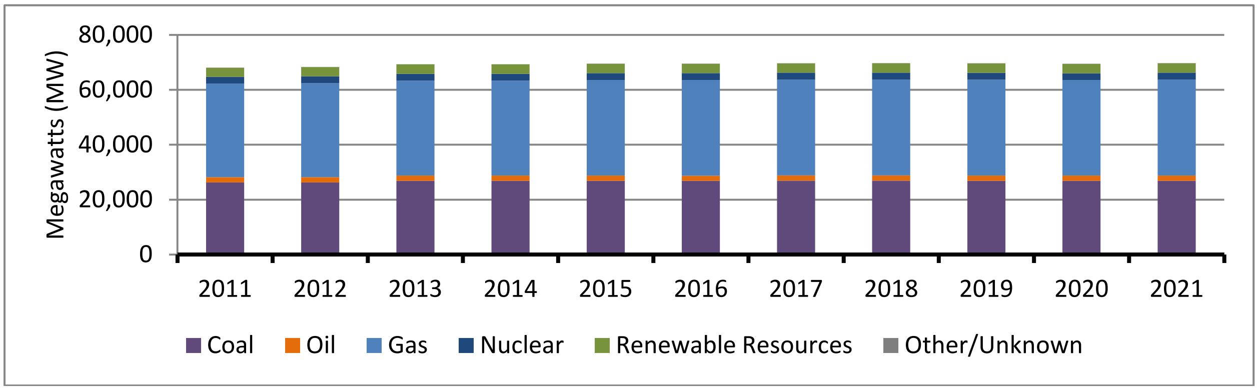


Figure E-36: Projected Change in SERC-W Summer On-Peak Capacity Fuel Mix

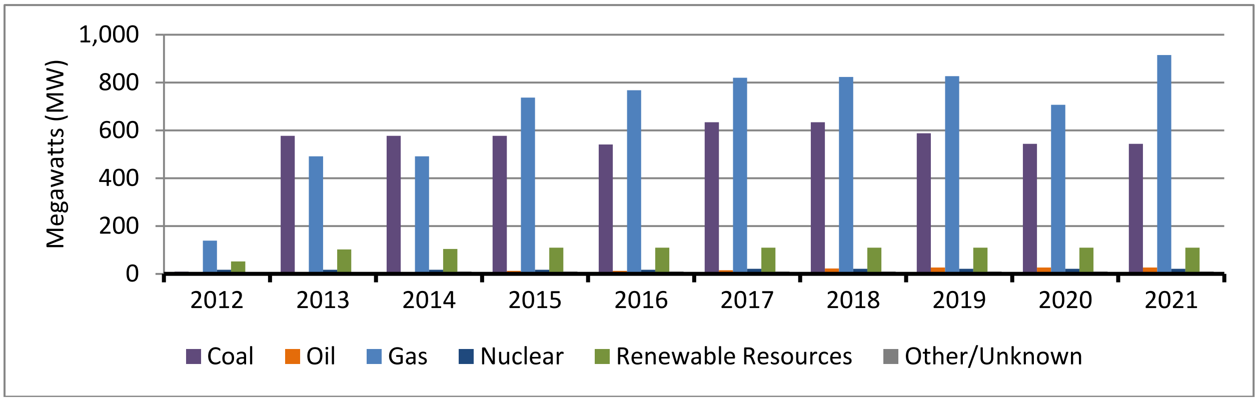


Figure E-37: Projected SPP Summer On-Peak Capacity Fuel Mix

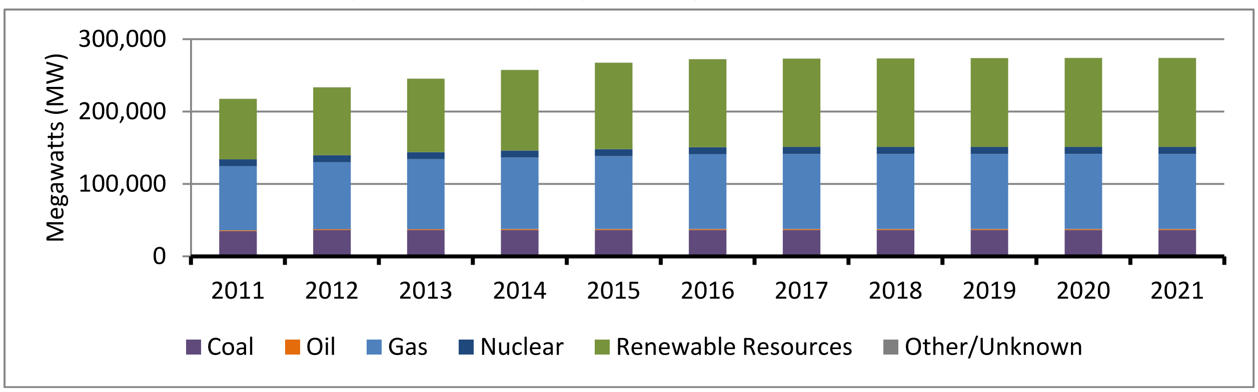


Figure E-38: Projected Change in SPP Summer On-Peak Capacity Fuel Mix

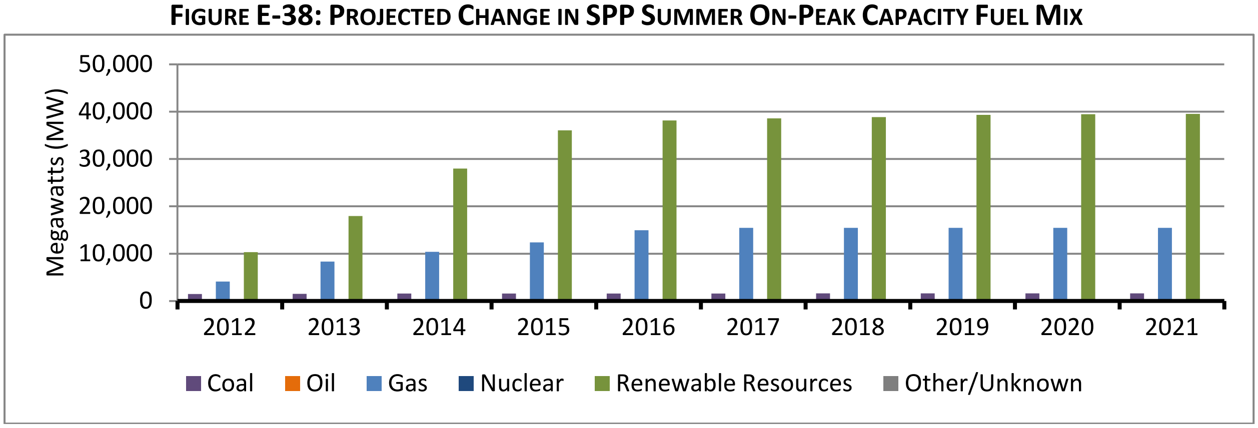


FIGURE E-39: PROJECTED WECC NON-COINCIDENT SEASONAL ON-PEAK CAPACITY FUEL MIX

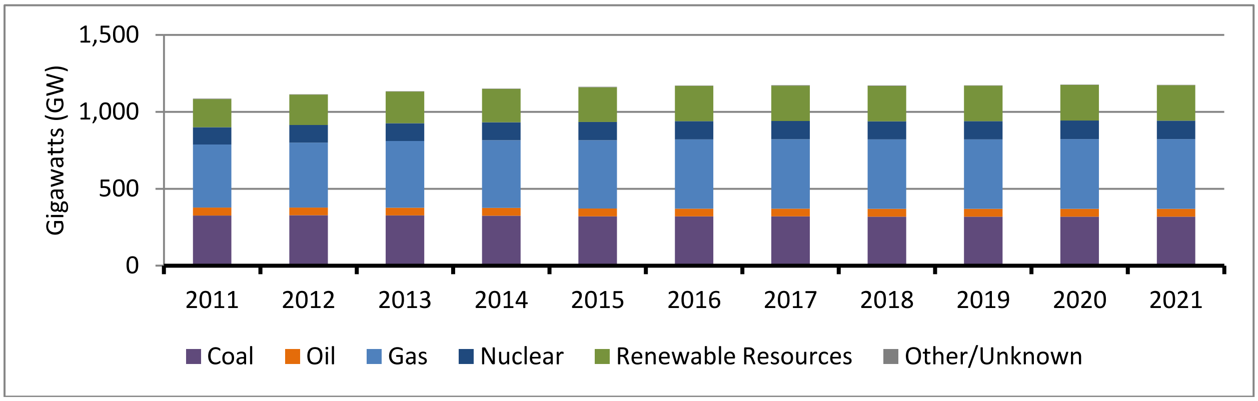
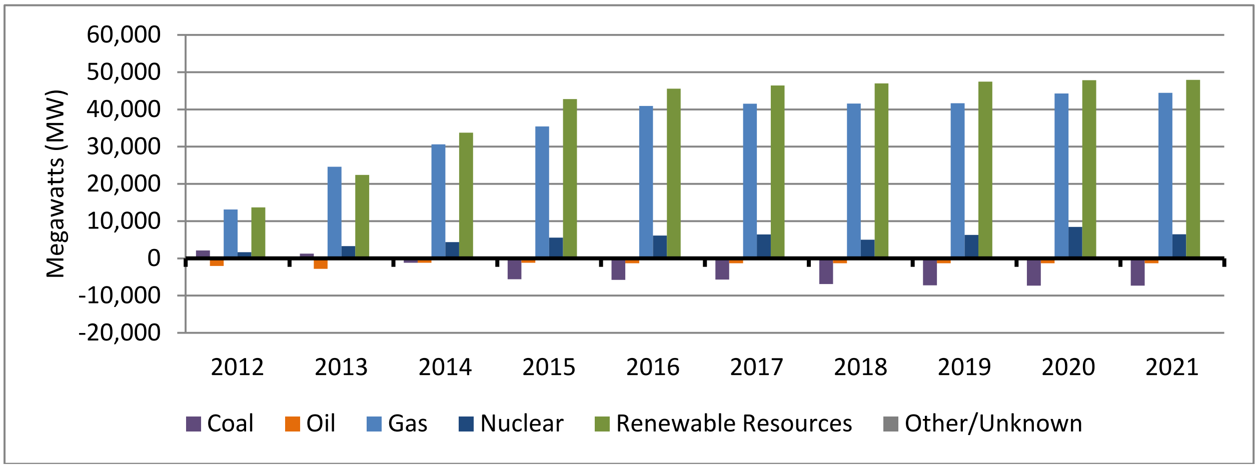


FIGURE E-39: PROJECTED CHANGE IN WECC NON-COINCIDENT SEASONAL ON-PEAK CAPACITY FUEL MIX



Appendix F: Response Time Provided By Line Pack

Overview

The term "line pack" is used to refer to the quantity of natural gas stored in the gas pipeline over and above the perceived minimum required operating pressure of the line. The excess gas is stored in the pipeline by increasing the pressure. This "line pack" can be used as a cushion in gas line operation. If more gas is required, the excess gas can be delivered to end users and the line pack reduced. However, gas pipelines are rarely pressurized with line pack to the line's maximum allowable operating pressure (MAOP), since operating at MAOP can limit the pipelines operational flexibility. For example, if an end user such as a gas-fired electric generation unit shuts down before a compressor station is proportionally turned down, excess gas can be pressurized in this transition period and thus exceed the MAOP.

Many parameters have an impact on the quantity of line pack available:

- Gas pipeline diameter (or number of lines),
- Distance between compressor stations,
- Pressure requirements of the end users, and;
- Size or capacity of the end user's equipment.

The other key to using line pack as a cushion is the response time needed for the pipeline to increase or decrease its compressor capacity to the changing demand for gas in order to maintain line pack. Figures F-1 through F-3 contain illustrations of response times provided for several different types of electric utility units by pipeline line pack under various operating conditions. As the tables in these exhibits illustrate, the response time can be changed from days to minutes, in the case of 1,500 MW of new combustion turbines that need 450 to 500 psi to operate properly.

One of the most significant conclusions from Figures F-1 through F-3 is that electric units should be connected to the largest diameter and highest pressure pipeline that exists in their region in order to safeguard against unexpected occurrences. Unfortunately, in some areas there are not a lot of choices. Nevertheless, assuming an electric unit can be supplied by a 36" diameter pipeline, Figures F-4 summarizes the response time for a variety of 36" diameter pipeline scenarios. Included in these scenarios are examples for the most recent pipelines added to the interstate pipeline grid. These pipelines, while few in number, have a MAOP of 1,440 psi. Also, incorporated in these scenarios are the typical pipelines in the industry (i.e., MAOP between 800 and 1,200 psi), as well as 500 psi MAOP pipeline, which exist in some regions. The latter is a very undesirable choice for a modern electric unit.

FIGURE F-1: RESPONSE TIME FOR 36" PIPELINE

I. Best Available Response Time Provided by Ideal Line Pack[(1)] (36" Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 600 psi)[(1)]			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	6.6 hours	1.3 hours	26 minutes
Conventional Combustion Turbines (250 psi)	1.0 days	4.8 hours	1.6 hours
B. High Pressure Lines (1,100 psi MAOP at 800 psi)[(1)]			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	20 hours	4.0 hours	1.3 hours
Conventional Combustion Turbines (250 psi)	1.5 days	7.5 hours	2.5 hours
II. Response Time Provided By Off Center Line Pack [(1)] (36" Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 650 psi) [(1)]			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	3.3 hours	40 minutes	13 minutes
Conventional Combustion Turbines (250 psi)	20 hours	4.0 hours	1.3 hours
B. High Pressure Lines (1,100 psi MAOP at 800 psi)[(1)]			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	10 hours	2.0 hours	40 minutes
Conventional Combustion Turbines (250 psi)	27 hours	5.3 hours	1.8 hours

(1) Operated at one-quarter or three-quarter pressure range between 500 psi and MAOP

FIGURE F-2: RESPONSE TIME FOR 24" PIPELINE

I. Response Time Provided By Off Center Line Pack(1) (24" Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 600 psi or 650 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	2.9 hours	3.5 hours	12 minutes
Conventional Combustion Turbines (250 psi)	10.7 hours	2.1 hours	43 inutes
B. High Pressure Lines (1,100 psi MAOP at 800 psi or 950 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	8.9 hours	1.8 hours	35 minutes
Conventional Combustion Turbines (250 psi)	16 hours	3.3 hours	1.1 hours
II. Response Time Provided By Off Center Line Pack (1) (36" Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 550 psi or 650 psi) (1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	1.5 hours	18 minutes	6 minutes
Conventional Combustion Turbines (250 psi)	8.9 hours	1.8 hours	35 inutes
B. High Pressure Lines (1,100 psi MAOP at 650 psi or 950 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	4.4 hours	53 minutes	18 minutes
Conventional Combustion Turbines (250 psi)	12 hours	2.4 hours	48 minutes

(1) Operated at one-quarter or three-quarter pressure range between 500 psi and MAOP

Lastly, the x-axis in Figure F-4 has been converted to the number of megawatt hours (MWh) that line pack could provide under adverse circumstances, which is different than the more simplified number of minutes used in the tables contained in Figures F-1 through F-3. There are two x-axes, namely (1) the number of MWh for a combined cycle unit with an average 7,200 BTU/kWh heat rate and (2) the number of MWh for a combustion turbine with an average 11,000 BTU/kWh heat rate.

Booster Compression

One approach electric utilities can use to minimize the impact of the possibility of receiving low pressure gas supplies is to install booster compression. Some manufacturers of combustion-turbine units that need 450 to 500 psi of natural gas, can supply compressors for $12/kW to $24/kW. However, these on-site fuel gas compressors only marginally extend the response time needed for the new combustion turbines. Nevertheless, booster compression is useful when gas pressures swing above and slightly below the required levels.

Backup Fuel

The other key mechanism for safeguarding against the potential loss of gas supplies or receipt of low pressure gas supplies is to have dual-fuel capability, such that the unit can switch to an alternative fuel (e.g., residual-fuel oil or distillate). While historically this was a very common option for the industry, particularly during the era of gas-fired, or dual-fired, steam generators, it is no longer a particularly viable option for the industry. The modern combined cycle unit, with its superior efficiency, has replaced almost completely the gas-fired steam generator. In addition, the air permits for most modern combined cycle or combustion turbine units restrict significantly the use of alternative fuels. As a result, many modern gas-fired units do not have dual-fuel capability and those units that are dual-fuel capable very seldom use their dual-fuel capability.[130]

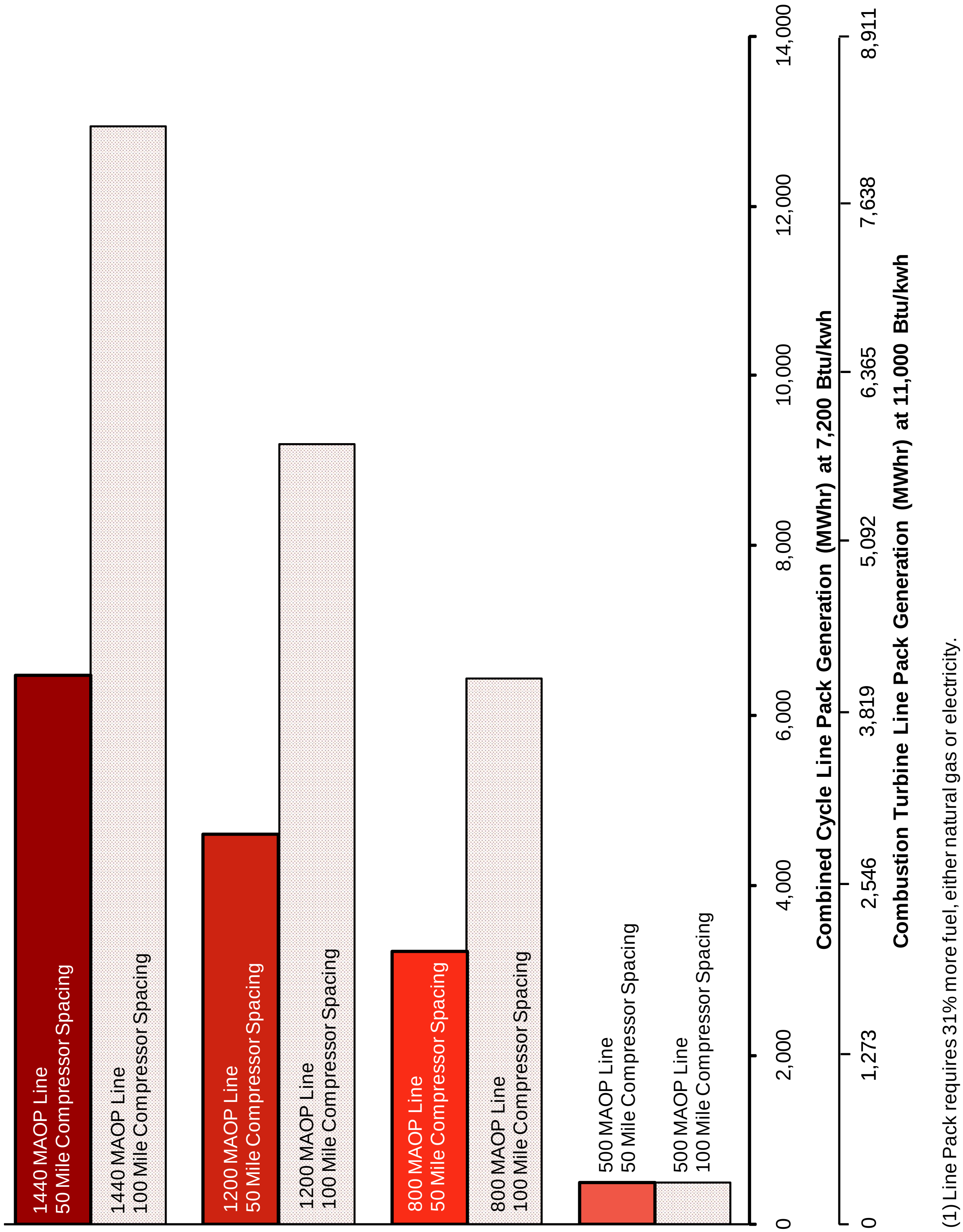
[130] See EPRI, Natural Gas Price Uncertainty: Establishing Price Floors (1012249), January 2007 and Impact of Natural Gas Market Conditions on Fuel Flexibility Needs for Existing and New Power Generation (1004600), January 2002.

FIGURE F-3: RESPONSE TIME FOR 16” PIPELINE

I. Best Available Response Time Provided By Ideal Line Pack(1) (16” Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 600 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	1.3 hours	16 minutes	5 minutes
Conventional Combustion Turbines (250 psi)	4.8 hours	58 minutes	19 minutes
B. High Pressure Lines (1,100 psi MAOP at 800 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	4 hours	48 minutes	16 minutes
Conventional Combustion Turbines (250 psi)	7.2 hours	1.5 hours	30 inutes
II. Response Time Provided By Off Center Line Pack (1) (16” Gas Pipeline at 40 Miles)			
A. Lower Pressure Lines (700 psi MAOP at 550 psi or 650 psi) (1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	40 minutes	8 minutes	2.5 minutes
Conventional Combustion Turbines (250 psi)	4 hours	48 minutes	16 minutes
B. High Pressure Lines (1,100 psi MAOP at 650 psi or 950 psi)(1)			
	Operating Capacity		
	100 MW	**500 MW**	**1,500 MW**
New Combustion Turbines (500 psi)	2 hours	24 minutes	8 minutes
Conventional Combustion Turbines (250 psi)	5.4 hours	1.1 hours	22 minutes

(1) Operated at one-quarter or three-quarter pressure range between 500 psi and MAOP

FIGURE F-4: RESPONSE TIME FOR 36" DIAMETER PIPELINE UNDER VARIOUS SCENARIOS



Appendix G: Pipeline Design Fundamentals

While it is beyond the scope of this document to present the detailed equations that are used for designing a transmission system, some insights to the key attributes of pipeline design are useful.[131] At the simplest level, the design of transmission system involves determining the lowest cost alternative of pipeline capacity (*i.e.*, usually diameter) and compression for delivering a required load over a set distance. Additionally, the possibility of future system expansion and other elements are often incorporated into the overall design.

PIPELINES

With respect to the pipeline component of the design, two approaches have been taken by the industry, namely steady state analysis (*i.e.*, independent of time) and transient flow analysis. While the former still has some value in the industry, most modern pipelines use transient flow analysis. The latter requires the use of considerable computing capacity that was not readily available in the earlier days of the industry (*e.g.*, pre World War II). As a result, pipeline engineering firms and others are now using transient hydraulic gas flow analysis to plan, design, model, simulate, and operate pipeline facilities with highly variable loads.[132] Such computer simulation for transient analysis basically consists of numerical solutions in space and time of the simultaneous partial differential equations that govern the physics of hydraulic flow and pressure loss. The four basic equations for numerical solution techniques are:

- Equation of State;
- Continuity Equation;
- Momentum Equation; and,
- Flow Area Equation.

The time dependent partial differential equations derived from these four equations are also being solved for the special case of time independent variables to yield many of the well known steady state gas flow equations.

The initial step by the industry to develop sophisticated pipeline design equations occurred in 1912 when key factors, such as pipeline diameter and the coefficient of friction for the roughness of the pipe, were combined into the Weymouth Equation. While the Weymouth Equation represents only a steady-state equation, it still is used within the industry for certain applications. Subsequently, in the early 1940s, expressions for the Reynolds Number under turbulent conditions were developed and incorporated into a pipeline design equation known as the Panhandle A Equation. The Panhandle A Equation subsequently was modified in 1956, which became known as the Panhandle B Equation and is still in use in the industry today.

19 This includes jet fuel, kerosene, and diesel fuel.

[131] For a complete assessment of pipeline design and the detailed equations used to develop pipeline systems and the associated level of compression see EPRI, *Pipelines to Power Lines: Gas Transportation for Electricity* (TR-104787), January 1995, Chapter 4.

[132] Gas flow velocity varies with the pressure at any location in a pipeline.

Compressors

The other key component to pipeline design is compressors, which are used to offset the declines in pipeline pressure that occur as gas is transported over distances.[133] While there are several kinds of compressors that may be used, the most widely used compressors are the less flexible, but less expensive, reciprocating compressors and the more flexible, but expensive, combustion turbine driven centrifugal compressors.[134] While it is common to use pipeline fuel (*i.e.*, natural gas) to operate both reciprocating and combustion turbine driven centrifugal compressors, compressors can also be driven by electric motor. There are specific design equations for each type of compressor that are available in other documents.[135]

Pipelines generally use electric compressors to meet air emission requirements under the Clean Air Act in non-attainment areas. The use of electric compressors and their vulnerability to outages is something both industries must evaluate and subsequently design preventative measures to ensure electric compressors are on dedicated, protected circuits.

System Design

Pipeline designs, as well as expansions, involve the integration of the industry equations for pipelines and system compression. These basic tools are used to assess the least cost combination of the following variables, although at times other variables, such as permitting issues, reliability and future expansions, are considered:

- Pipeline diameter,
- Pipeline wall thickness (impacts MAOP),[136]
- Load Factor,
- Distance from supply to market, and
- Number and size of compressor stations.

While transient flow analysis is complex, there are a number of basic concepts and/or tradeoffs involved in pipeline design. Figure G-1 summarizes several of these key concepts. As noted in Graph A, the capacity of the pipeline increases exponentially as the diameter increases. In addition, pipeline capacity increases linearly as pressure increases (*i.e.*, Graph B), as does the wall thickness of the pipe and the cost of the pipe. Furthermore, as distance increases the pressure declines exponentially (*i.e.*, Graph C). Finally, there is an eventual limitation to the distance gas will flow in a given size pipe. As a result, the use of pipeline compression is incorporated into the system design in order to restore pipeline pressure along the route (*i.e.*, Graph D).

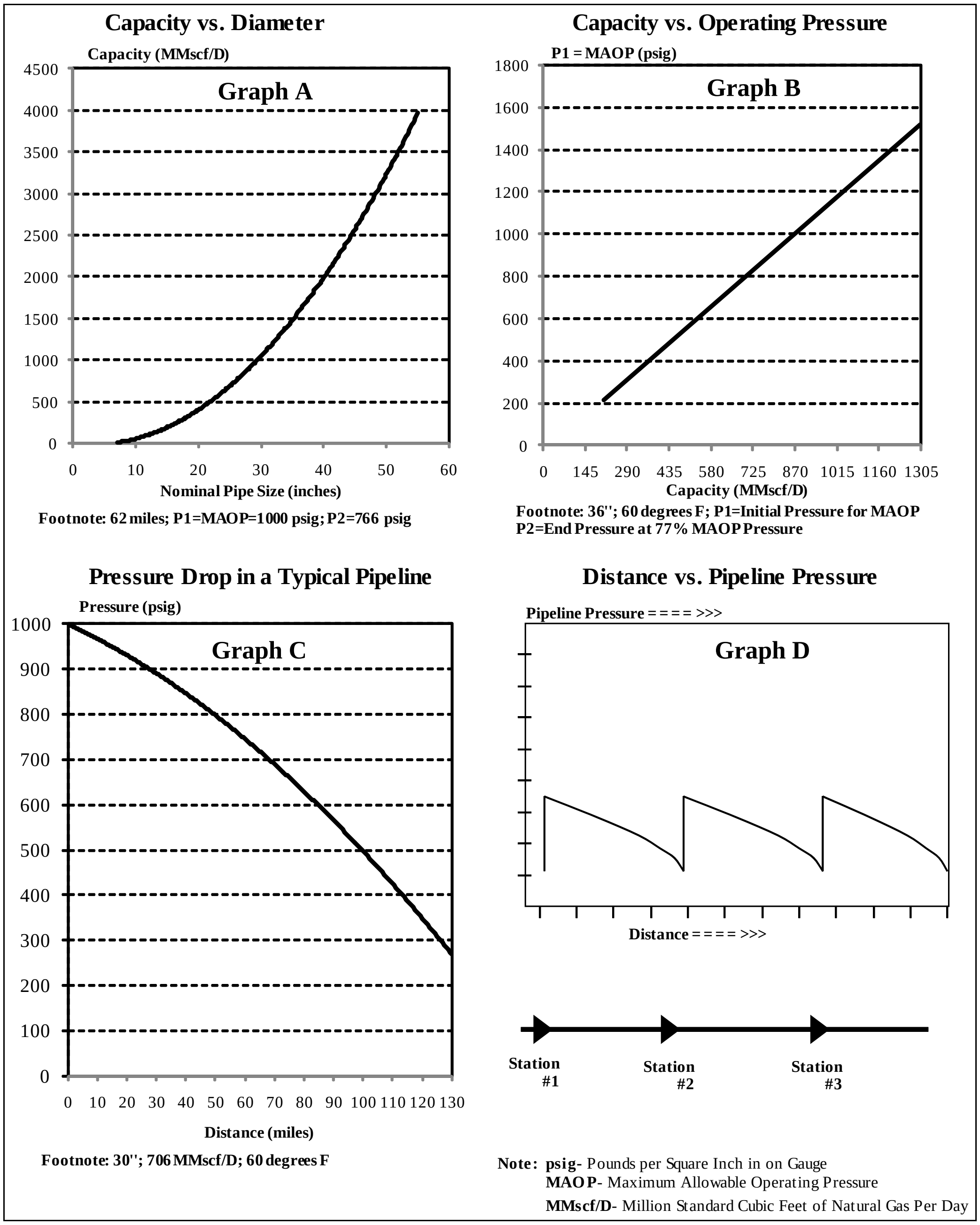
[133] Maintaining pressure is critical in order to provide the required volume of gas (*i.e.*, both gas density and speed), at the terminus of the pipeline.

[134] More or less flexible and more or less expensive will ultimately depend on the application. In some applications, a reciprocating compressor has a higher installed cost but a more flexible operating range

[135] See EPRI, Pipelines to Power Lines: Gas Transportation for Electricity (TR-104787), January 1995, Chapter 4.

[136] Maximum Allowable Operating Pressure (MAOP) refers to the wall strength of a pressurized cylinder such as a pipeline or storage tank and how much pressure the walls may safely hold in normal operation. The MAOP is less than the MAWP (maximum allowable working pressure). MAWP is the maximum pressure based on the design codes that the weakest component of a pressure vessel can handle.

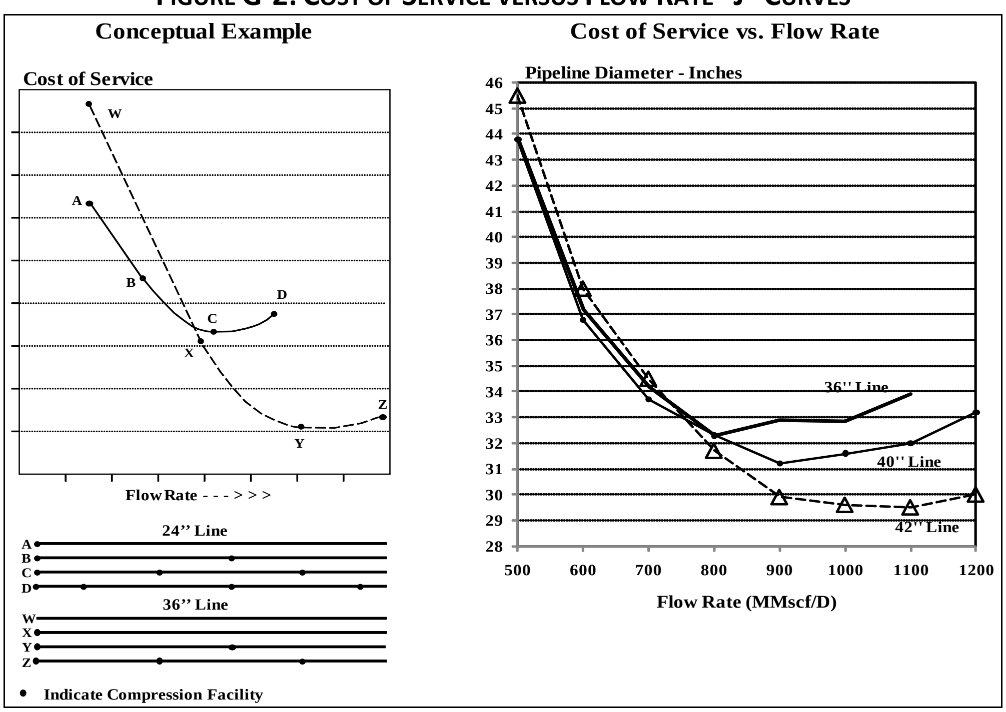
FIGURE G-1: TYPICAL RELATIONSHIPS FOR KEY PIPELINE PARAMETERS



Other important design concepts include the higher the pressure of the system, the more cost-effective the system will be. However, there are practical limitations (*e.g.*, materials strength and welding) for pipeline pressures, with the current upper limit for a pipeline MAOP being 1,440 psia. Also, the distance to the ultimate load center is usually fixed. As a result, system design typically results in determining the optimum combination of the other variables (*e.g.*, diameter, load factor and number of compressor stations). In addition, it is possible to come up with a series of designs that meet the overall system design if load factor is held constant. However, one unique attribute of each of these potential designs is what is referred to in the industry as the 'J Curve', which is illustrated in Figure G-2. In pipeline system design for a given diameter pipe overall system costs decline as compression is added (*i.e.*, economics of scale). However, there is an optimum least cost point after which unit costs actually increase if additional compression is added. The schematic illustrating this looks like a 'J', hence the terminology 'J Curve'.

As previously mentioned, it is possible to develop a series of designs that meet the overall system's requirements. This is illustrated in the left graphic in Figure G-2, which compares and contrasts designs for both 24 and 36 inch systems. The 24 inch system incorporates one to four compressors, while the 36 inch system incorporates one to three compressors. As noted, the effective cost solutions for the two systems are very close when three compressors are used for the 24 inch system and one compressor is used for the 36 inch system. However, in this case the 36 inch system would be more advantageous if there was a strong likelihood for future expansion. This basic cost concept is that lower initial cost can be obtained by the use of smaller pipeline diameter while over the long-term with future expansion a large diameter system likely is the optimum choice. This is illustrated in the right-most graphic in Figure G-2.

FIGURE G-2: COST OF SERVICE VERSUS FLOW RATE "J" CURVES



Reliability Assessment Subcommittee Roster

Chairman	Mark J. Kuras Senior Lead Engineer	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403	(610) 666-8924 (610) 666-4779 Fx kuras@pjm.com
Regional Entity Representatives – Members of the *Electric Reliability Organization: Reliability Assessment and Performance Analysis Group* (ERO-RAPA Group)			
Vice Chairman FRCC RE Staff	Vince Ordax Manager of Planning	Florida Reliability Coordinating Council 1408 N. Westshore Blvd Tampa, Florida 33607	(813) 207-7988 (813) 289-5646 Fx vordax@frcc.com
MRO RE Staff	John Seidel Senior Mgr, Event Analysis and Reliability Improvement	Midwest Reliability Organization 2774 Cleveland Avenue N. Roseville, Minnesota 55113	(651) 855-1716 (651) 855-1712 Fx ja.seidel@midwestreliability.org
NPCC RE Staff	John G. Mosier, Jr. Assistant Vice President of System Operations	Northeast Power Coordinating Council, Inc. 1040 Avenue of the Americas, 10th Floor New York, New York 10018-3703	(212) 840-1070 (212) 302-2782 Fx jmosier@npcc.org
RFC RE Staff	Paul D. Kure Senior Consultant, Resources	ReliabilityFirst Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	(330) 247-3057 (330) 456-3648 Fx paul.kure@rfirst.org
SERC RE Staff	Kevin Berent Manager of Reliability Assessment	SERC Reliability Corporation 2815 Coliseum Centre Drive Suite 500 Charlotte, North Carolina 28217	(704) 940-8237 KBerent@serc1.org
SPP RE Staff	David Kelley Manager, Engineering Administration	Southwest Power Pool, Inc. 415 N. McKinley Street, Suite 140 Little Rock, Arkansas 72205-3020	(501) 688-1671 (501) 821-3245 Fx dkelley@spp.org
TRE RE Staff	Curtis Crews Lead Reliability Assessment Engineer	Texas Reliability Entity, Inc. 805 Las Cimas Parkway Suite 200 Austin, Texas 78746	(512) 583-4989 (512) 583-4903 Fx curtis.crews@texasre.org
WECC RE Staff	Layne Brown Loads & Resources Senior Engineer	Western Electricity Coordinating Council 155 North 400 West, Suite 200 Salt Lake City, Utah 84103	(801) 582-0353 (801) 582-3981 Fx lbrown@wecc.biz

MRO	John Lawhorn, P.E. Senior Director, Regulatory and Economic Studies	Midwest ISO, Inc. 1125 Energy Park Drive St. Paul, Minnesota 55108	(651) 632-8479 (651) 632-8417 Fx jlawhorn@midwestiso.org
MRO	Hoa V. Nguyen Resource Planning Coordinator	Montana-Dakota Utilities Co. 400 North 4th Street Bismarck, North Dakota 58501	(701) 222-7656 (701) 222-7872 Fx hoa.nguyen@mdu.com
RFC	Mohammed Ahmed, P.E. Manager, East Training Planning	AEP 700 Morrison Road Gahanna, Ohio 43230	614 552 1669 (614) 552-1676 Fx mahmed@aep.com
RFC	Esam A.F. Khadr Director – Electric Delivery Planning	Public Service Electric and Gas Co. 80 Park PlazaT-14A Newark, New Jersey 07102	(973) 430-6731 (973) 622-1986 Fx Esam.Khadr@pseg.com
SERC	Hubert C Young Manager of Transmission Planning	South Carolina Electric & Gas Co. 220 Operations Way MC J37 Cayce, South Carolina 29033	(803) 217-2030 (803) 933-7264 Fx cyoung@scana.com
WECC	James Leigh-Kendall Manager, Reliability Compliance and Coordination	Sacramento Municipal Utility District 6002 S Street, B303 Sacramento, California 95852	(916) 732-5357 (916) 732-7527 Fx jleighk@smud.org
TRE	Dan M Woodfin Director, System Planning	Electric Reliability Council of Texas, Inc. 2705 West Lake Dr. Taylor, Texas 76574	(512) 248-3115 (512) 248-4235 Fx dwoodfin@ercot.com
MRO Alternate	Salva R. Andiappan Manager - Reliability Assessment and Performance Analysis	Midwest Reliability Organization 2774 Cleveland Avenue N. Roseville, Minnesota 55113	(651) 855-1719 (651) 855-1712 Fx sr.andiappan@midwestreliability.org
RFC Alternate	John Idzior Engineer	ReliabilityFirst Corporation 320 Springside Dr. Suite 300 Akron, Ohio 44333	330-247-3059 (330) 456-3648 Fx john.idzior@rfirst.org
SERC Alternate	Barbara A. Doland Data Analyst	SERC Reliability Corporation 2815 Coliseum Centre Drive Suite 500 Charlotte, North Carolina 28217	704-940-8238 704-357-7914 Fx BDoland@serc1.org
SPP Alternate	Alan C Wahlstrom	16101 La Grande Dr. Suite 103 Littlerock, Arkansas 72223	(501) 688-1624 (501) 664-6923 Fx awahlstrom@spp.org

ISO/RTO	Jameson Smith Manager, Regulatory Studies	Midwest ISO, Inc. 1125 Energy Park Drive Saint Paul, Minnesota 55108	6516328411 jtsmith@midwestiso.org
ISO/RTO	Peter Wong Manager, Resource Adequacy	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040	413-535-4172 413-540-4203 Fx pwong@iso-ne.com
DCWG Chair	K. R. Chakravarthi Manager, Interconnection and Special Studies	Southern Company Services, Inc. 600 North, 18th Street Bin:13N-8183 Birmingham, Alabama 35291	(205) 257-6125 (205) 257-1040 Fx krchakra@southernco.com
LFWG Chair	Bob Mariotti Supervisor - Short Term Forecasting	DTE Energy 2000 Second Avenue 787WCB Detroit, Michigan 48226-1279	(313) 235-6057 (313) 235-9583 Fx mariottir@dteenergy.com
OC Liaison	Jerry Rust President	Northwest Power Pool Corporation 7505 NE Ambassador Place, Ste R Portland, Oregon 97035	503-445-1074 503-445-1070 Fx jerry@nwpp.org
OC Liaison	James Useldinger Manager, T&D System Operations	Kansas City Power & Light Co. PO Box 418679 Kansas City, Missouri 64141	(816) 654-1212 (816) 654-1189 Fx jim.useldinger@kcpl.com

North American Electric Reliability Corporation Reliability Assessment Staff Roster

North American Electric Reliability Corporation
3353 Peachtree Road NE
Atlanta, Georgia 30326
Telephone: 404.446.2560

Reliability Assessment

Mark G. Lauby	Vice President and Director of Reliability Assessment and Performance Analysis	mark.lauby@nerc.net
John Moura	Manager, Reliability Assessment	john.moura@nerc.net
Eric Rollison	Engineer, Reliability Assessment	eric.rollison@nerc.net
Elliott Nethercutt	Technical Analyst, Reliability Assessment	elliott.nethercutt@nerc.net
Michelle Marx	Administrative Assistant, Reliability Assessment and Performance Analysis	michelle.marx@nerc.net
Danielle Landry	Intern, Reliability Assessment and Performance Analysis	danielle.landry@nerc.net

Consultant

Stephen L. Thumb	Principal, Energy Ventures Analysis, Inc.	thumb@evainc.com

Energy Ventures Analysis, Inc. is an internationally recognized energy consulting firm focused on the coal, natural gas, emissions and electric power sectors. Since 1981, EVA has been considered the go-to firm when tough decisions need to be made in the energy industry. EVA's expertise is embodied in our energy and environmental forecasts, periodic multi-client reports, and analyses of projects for electric power utilities, fuel producers/buyers/shippers, financial institutions, and expert testimony in litigation and regulatory proceedings.